Levy Nuclear Plant Units 1 and 2

COL Application

Part 1

General and Financial Information

Revision 1

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1.0 GENERAL AND FINANCIAL INFORMATION

1.1 GENERAL INFORMATION

Pursuant to Sections 103 and 185(b) of the Atomic Energy Act, and 10 CFR Part 52, Subpart C, Florida Power Corporation doing business as Progress Energy Florida, Inc., a wholly-owned subsidiary of Progress Energy, Inc. (Progress Energy), hereby applies to the U.S. Nuclear Regulatory Commission (NRC) for a combined license (COL) to construct and operate Levy Nuclear Plant, Units 1 and 2 (LNP 1 and 2). LNP 1 and 2 is a two-unit Westinghouse AP1000 standard design for a pressurized water reactor. Progress Energy Florida, Inc., also applies for such other licenses as would be required to possess and use source, special nuclear and byproduct material in connection with the operation of LNP 1 and 2.

Progress Energy, together with its subsidiaries, operates as an integrated energy company serving the southeast region of the United States. The company engages in the generation, transmission, distribution, and sale of electricity in North Carolina, South Carolina, and Florida. As of December 31, 2006, Progress Energy had approximately 21,300 megawatts of regulated electric generation capacity and served approximately 3.1 million retail electric customers. Progress Energy, formerly known as CP&L Energy, Inc., was founded in 1925 and is headquartered in Raleigh, North Carolina.

Progress Energy has a strong operational record and a growing customer base. The company is focusing on the regulated electric utility business and expects to complete divestitures of nonregulated businesses in 2008. This will make Progress Energy the largest utility focused solely on the regulated electric utility business. Our focus on core business has achieved significant results. In 2006, the operational excellence achieved by Progress Energy resulted in the industry’s highest honor: the Edison Award. In addition, the four nuclear plants operated by Progress Energy are consistently ranked among the industry’s best in production, safety, and cost efficiency.

Progress Energy’s service territories are among the fastest-growing areas of the country. The company currently serves approximately 3.1 million customers in the Carolinas and Florida, adding more than 64,000 new customers last year alone. To meet this growing demand, Progress Energy expects to add approximately 12,500 megawatts of new generation by 2025, which will include two base load nuclear units in North Carolina and two base load nuclear units in Florida.

Our strategic challenge is to address the growth demands of the Carolinas and Florida while balancing the needs of customers, shareholders, and employees. To address this challenge, Progress Energy is implementing a balanced approach. The three main elements of this balanced solution are: increasing energy efficiency and supporting development of renewable energy sources for the future; modernizing existing plants to produce energy more cleanly and efficiently using state-of-the-art technology; and investing in new generating plants. The results of this approach will be a highly reliable energy supply, more stable electricity prices, a cleaner environment, and less dependence on imported energy.

The addition of nuclear base load generation in both North Carolina and Florida is required to meet this growth. In addition to this Combined License Application (COLA) for LNP 1 and 2, Progress Energy has submitted a COLA to construct and operate two AP1000 nuclear units at the Shearon Harris Nuclear Power Plant site near Raleigh, North Carolina.

This application and supporting environmental report are intended to provide sufficient information for the NRC to complete its technical and environmental reviews and allow the NRC to make the finding required by 10 CFR 52.97 in support of the issuance of a COL for LNP 1 and 2. The following is the application filing and content information required by 10 CFR 50.33.

1.1.1 NAME OF APPLICANT

Progress Energy Florida, Inc.

1.1.2 ADDRESS OF APPLICANT

Progress Energy Florida, Inc.
100 Central Avenue
St. Petersburg, FL 33701-3324

1.1.3 DESCRIPTION OF BUSINESS OCCUPATION OF APPLICANT

Progress Energy is a holding company that includes regulated subsidiaries, Progress Energy Florida, Inc. (PEF) and Progress Energy Carolinas, Inc. (PEC). PEF is primarily engaged in the generation, transmission, distribution, and sale of electricity in portions of central and north Florida. PEF serves approximately 1.7 million customers in a territory encompassing over 20,000 square miles, including the cities of St. Petersburg, Clearwater, and areas surrounding Orlando.

PEF is primarily engaged in the generation, distribution, and sale of electricity in portions of Florida. PEF owns and operates the Crystal River plant.

- Crystal River - The single-unit, 838-MW Crystal River Nuclear Plant is located near Crystal River, FL, on a site that also includes four coal-fired generating units that generate 2,313 MW.

PEC owns and operates the following nuclear units:

- Shearon Harris – The single-unit, 900-MW Harris Nuclear Plant is located near New Hill, N.C. It is Progress Energy's newest nuclear plant, beginning commercial operation in 1987.

- Brunswick - The two-unit, 1,875-MW Brunswick Nuclear Plant is located near Southport, N.C. An additional 244 megawatts of electrical generation was added to the plant's output from 2002 to 2005 as part of an extended power uprate program that upgraded much of the plant's equipment.

- Robinson - The single-unit, 710-MW Robinson Nuclear Plant is located near Hartsville, S.C. This site also includes a coal-fired unit that generates 180 MW and a combustion turbine unit that generates 15 MW.

Progress Energy is located in Raleigh, NC and is subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005). PEC and PEF are regulated public utilities. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC), the NRC and the FERC. PEF is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), the NRC and the FERC.

At the end of 2006, PEF had a summer peak generating capacity of 10,752 MW. PEF develops its resource plans based on maintaining capacity margins in the 11 percent to 17 percent range to account for the forecasting uncertainty in the long-term or potential delays in bringing capacity online. The net energy for load is expected to increase by 2.6 percent per year from 2007 to 2016. The growth in the population is expected to reach an additional 7 million people by the year 2031.

1.1.4 ORGANIZATION AND MANAGEMENT OF APPLICANT

PEF is a corporation organized and existing under the laws of the State of Florida. PEF is a wholly-owned subsidiary of Progress Energy and is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. PEF makes this application on its own behalf and is not acting as an agent or representative of any other person.

The names and addresses of Progress Energy directors and principal officers are listed below. All persons listed are U. S. citizens.

Director	Address
James E. Bostic Jr.	Atlanta, GA
Harris. E DeLoach, Jr.	Hartsville, SC
James B. Hyler, Jr.	Raleigh, NC
William D. (Bill) Johnson	Raleigh, NC
Robert W. Jones	Bedford, NY
W. Steven Jones	Chapel Hill, NC
E. Marie McKee	Corning, NY
John H. Mullin, III	Brookneal, VA
Charles W. Pryor, Jr.	Lynchburg, VA
Carlos A. Saladrigas	Miami, FL
Theresa M. Stone	Boston, MA
Alfred C. Tollison, Jr.	Marietta, GA

Principal Officers	Address
William D. (Bill) Johnson Chairman, Chief Executive Officer, and President - Progress Energy, Inc.	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Jeffrey (Jeff) J. Lyash Executive Vice President – Corporate Development Group Progress Energy, Inc.	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Jeffrey (Jeff) A. Corbett Senior Vice President - Energy Delivery Progress Energy Carolinas	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Lloyd M. Yates President and Chief Executive Officer Progress Energy Carolinas	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
James (Jim) Scarola Senior Vice President and Chief Nuclear Officer – Nuclear Generation Progress Energy Carolinas and Progress Energy Florida	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Vincent Dolan President and Chief Executive Officer Progress Energy Florida	Progress Energy, Inc. 100 Central Avenue St. Petersburg, FL 33701-3324
John R. McArthur Executive Vice President and Corporate Secretary Progress Energy, Inc.	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Mark F. Mulhern Senior Vice President and Chief Financial Officer Progress Energy, Inc.	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Paula Sims Senior Vice President – Power Operations Progress Energy Carolinas and Progress Energy Florida	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748
Michael A. Lewis Senior Vice President - Energy Delivery Progress Energy Florida	Progress Energy, Inc. 100 Central Avenue St. Petersburg, Fl 33701-3324

Principal Officers	Address
Frank Schiller Senior Vice President – Compliance and General Counsel Progress Energy, Inc	Progress Energy, Inc. 410 S. Wilmington Street Raleigh, NC 27601-1748

1.1.5 CLASS AND PERIOD OF LICENSE SOUGHT AND AUTHORIZED USES

PEF requests issuance of a Class 103 Facility Operating License for a period of no less than 40 years beyond the Commission's determination in 10 CFR 52.103(g) or allowing operation during an interim period under 52.103(c). LNP 1 and 2 will be used to produce electricity for sale.

In addition, this application is for the necessary licenses issued under 10 CFR 30, 10 CFR 40, and 10 CFR 70 to receive, possess, and use byproduct, source and special nuclear material. Byproduct, source, and special nuclear material shall be in the form of sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring, calibration, and fission detectors in amounts as required. Byproduct, source, and special nuclear material in amounts as required, without restriction to chemical or physical form, shall be for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components. Special nuclear material shall be in the form of reactor fuel, in accordance with limitation for storage and amounts required for reactor operation, as described in Part 2 of this application.

1.1.6 ALTERATION SCHEDULE

PEF does not propose to alter any production or utilization facility in connection with this application.

1.1.7 REGULATORY AGENCIES AND LOCAL PUBLICATIONS

The Federal Energy Regulatory Commission and the FPSC are the principal regulators of PEF's electric operations in Florida.

Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Area and local news publications and addresses are provided below.

Citrus County Chronicle
1624 N. Meadowcrest Blvd
Crystal River, FL 34429

Ocala Star Banner
2121 S. W. 19th Avenue Road
Ocala, FL 34474

Chiefland Citizen
PO Box 980
Chiefland, FL 32644
Nature Coast Newscaster
PO Box 64
Yankeetown, FL 34498

1.1.8 RADIOLOGICAL EMERGENCY RESPONSE PLANS

Progress Energy's approach for development of the Levy Nuclear Plant Units 1 and 2 Emergency Plan submitted as part of the COL application (COLA) involved development of an emergency plan based on current NRC and Federal Energy Management Agency (FEMA) requirements and regulatory guidance into a document that addresses emergency preparedness for a new 2-unit site.

Emergency Preparedness Program elements described in the Levy Nuclear Plant Units 1 and 2 Emergency Plan were based, in part, on the elements currently in place at the Crystal River 3 (CR3) Nuclear Plant and described in the CR3 Radiological Emergency Response Plan, which meets all current NRC requirements and FEMA guidance.

Elements of the current CR3 Emergency Plan and the capability of the on-site and off-site emergency organizations to respond to, and recover from a classified emergency have been successfully demonstrated in actual events, periodic drills, and NRC/FEMA evaluated exercises in support of CR3. NRC Emergency Plan programmatic inspections and periodic independent 10 CFR 50.54 (t) audits indicate that the current CR3 Emergency Plan and Emergency Preparedness Program is maintained and updated appropriately in accordance with NRC requirements.

The Levy Nuclear Plant Units 1 and 2 Emergency Plan describes similar Emergency Preparedness Program elements and processes as the CR3 Radiological Emergency Response Plan; and both plans provide "reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency"."

The COLA emergency plan meets all current NRC requirements and regulatory guidance and was developed as a comprehensive "complete and integrated" emergency plan, in accordance with Regulatory Guide 1.206, Section C.I.13.3.1. The Levy Nuclear Plant Units 1 and 2 Emergency Plan, in conjunction with State and county plans, assures that adequate protective measures can be taken to protect on-site personnel and the public in the event of an emergency at the site.

2.0 FINANCIAL QUALIFICATIONS

2.1 CONSTRUCTION COSTS

Proprietary Information – Withheld under 10 CFR 2.390 (a)(4)
(See COL Application Part 9.1)

Proprietary Information – Withheld under 10 CFR 2.390 (a)(4)
(See COL Application Part 9.1)

Proprietary Information – Withheld under 10 CFR 2.390 (a)(4)
(See COL Application Part 9.1)

2.2 OPERATING COSTS

Progress Energy is an electric utility as defined in 10 CFR 50.2. Progress Energy generates and distributes electricity and recovers the cost of this electricity through cost-of-service based rates established by the North Carolina Public Utility Commission, South Carolina Public Service Commission, FPSC, and FERC. Thus, as addressed in 10 CFR 50.33(f), estimates of operating costs for the first 5 years of operation are not required to be submitted.

3.0 DECOMMISSIONING FUNDING ASSURANCE

In accordance with 10 CFR 50.33(k) and 10 CFR 50.75(b), a decommissioning report is provided as Attachment A. This report certifies that decommissioning will be provided in an amount no less than the amount required by 10 CFR 50.75(c)(1) adjusted using a rate at least equal to that stated in 10 CFR 50.75(c)(2). This amount is currently $373,401,956 for each unit. Updated certifications and financial instruments will be submitted in accordance with 10 CFR 50.75(e)(3); and after the NRC publishes notice in the Federal Register under 10 CFR 52.103(a), the decommissioning funding amount will be adjusted using a rate at least equal to that stated in 10 CFR 50.75(c)(2). The decommissioning funding amount will be covered by PEF by the external sinking fund method. PEF will collect decommissioning funding contributions through regulated, cost-of-service based rates.

3.1 DECOMMISSIONING COSTS AND FUNDING - STATUS REPORTING

In accordance with 10 CFR 50.75(e)(3), PEF will, two years before and one year before the scheduled date for initial loading of fuel, submit a report containing a certification updating the information described in 10 CFR 50.75(b)(1). PEF will periodically report on the status of decommissioning funding on LNP 1 and 2.

3.2 RECORDKEEPING PLANS RELATED TO DECOMMISSIONING FUNDING

In accordance with 10 CFR 50.75(g), PEF will retain records, until the termination of the license, of information important to the safe and effective decommissioning.

4.0 RESTRICTED DATA AND CLASSIFIED NATIONAL SECURITY INFORMATION

The combined license application for LNP 1 and 2 does not contain any Restricted Data or other Classified National Security Information, nor does it result in any change in access to any Restricted Data or National Security Information. In addition, it is not expected that activities conducted in accordance with the proposed combined license will involve such information. However, in the event that such information does become involved, and in accordance with 10 CFR 50.37, "Agreement limiting access to Classified Information," PEF will not permit any individual to have access to, or any facility to possess, Restricted Data or Classified National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR 25, "Access Authorization," and/or 10 CFR 95, Facility Security Clearance and Safeguarding of National Security Information and Restricted Data."

APPENDIX A DECOMMISSIONING REPORT

Table A-1 provides the estimate of the total decommissioning costs, in 2007 dollars, for each LNP unit, using the formula given in 10 CFR 50.75. This is based on a thermal power rating for the AP1000 of 3400 Megawatts, thermal (MWt).

Table A-1
Decommissioning Costs per Unit for LNP 1 and 2

Levy AP1000 NUCLEAR POWER UNIT (PWR)
CALCULATION OF CERTIFICATION AMOUNT
PER THE NUCLEAR REGULATORY COMMISSION
- DECEMBER 2007 UPDATE -

NRC REQUIRED MINIMUM DECOMMISSIONING AMOUNTS APPLICABLE (based on 10 CFR 50.75(c))*

MINIMUM AMOUNT (JAN. 1986 DOLLARS) REQUIRED TO DEMONSTRATE REASONABLE ASSURANCE OF FUNDS FOR DECOMMISSIONING:

Planned Reactor Power = 3400 MWt
NRC Minimum Amount = $105,000,000

Cost Elements in 1986 dollars:

FORMULA* = .65L + .13E +.22B

L = ESCALATION FACTOR FOR LABOR
E = ESCALATION FACTOR FOR ENERGY
B = ESCALATION FACTOR FOR WASTE BURIAL

LABOR COSTS	.65 x $105,000,000	=	$68,250,000
ENERGY COSTS	.13 x $105,000,000	=	13,650,000
WASTE BURIAL	.22 x $105,000,000	=	23,100,000
			$105,000,000

ESCALATION OF COST FACTORS TO DECEMBER 2007:

LABOR			$68,250,000	x	106.7 x 1.98 /100	(1)	=	$144,189,045
ENERGY (2)	.58P x $13,650,000	=	7,917,000	x	180.5/114.2	(2)	=	12,513,297
	.42F x $13,650,000	=	5,733,000	x	230.6/82.0	(2)	=	16,122,315
WASTE BURIAL			$23,100,000	x	8.683/1.000	(3)	=	200,577,300

MINIMUM AMOUNT OF DECOMMISSIONING COSTS (IN DECEMBER 2007 DOLLARS) $373,401,956

PARTICIPANTS	PERCENTAGE SHARE	MINIMUM AMOUNT OF DECOMMISSIONING COSTS PER NRC FORMULA (DECEMBER 2007 DOLLARS)
Power Agency	0.0000%	$0
SUBTOTAL - PARTICIPANTS	0.0000%	$0
PROGRESS ENERGY FLORIDA	100.0000%	$373,401,956
TOTAL	100.0000%	$373,401,956

Notes:
Labor and Energy indices are from the U.S. Department of Labor, Bureau of Labor Statistics, http://stats.bls.gov
(1) The labor adjustment factor has two components:
  (a) The December 2005 base labor adjustment factor of 1.98 for the South Region (based on January 1986 index base value of 100), sourced from NUREG-1307 Rev. 12 Table 3.2;
  (b) The December 2007 Employment Cost Index (ECI) of 106.7 (based on the December 2005 index base value of 100), sourced from Bureau of Labor Statistics Internet Data Page.
(2) Energy costs are composed of 58% electrical power and 42% fuel oil (per NUREG-1307).
  The escalation factor for electrical power is the December 2007 value of 180.5 divided by the January 1986 base value of 114.2.
  The escalation factor for light fuel oil is the December 2007 value of 230.6 divided by the January 1986 base value of 82.0.
(3) The escalation factor for waste burial is sourced from NUREG-1307 Rev. 12, Table 2.1.

APPENDIX B PROGRESS ENERGY, INC., FORM 10-K, FISCAL YEAR ENDED DECEMBER 31, 2007

Form 10-K

CAROLINA POWER & LIGHT CO - PGN

Filed: February 28, 2008 (period: December 31, 2007)

Annual report which provides a comprehensive overview of the company for the past year

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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, 2007

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.** 299 First Avenue North 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	( )	No	(X)
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.

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

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	( )
PEF	(X)

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

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

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, 2007, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $11,775,529,453. As of June 30, 2007, 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, 2007, 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 22, 2008, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	260,100,680
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 2008 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.

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GLOSSARY OF TERMS

We use the words "Progress Energy," "we," "us" or "our" with respect to certain information to indicate that such information relates to Progress Energy, Inc. and its subsidiaries on a consolidated basis. When appropriate, the parent holding company or the subsidiaries of Progress Energy are specifically identified on an unconsolidated basis as we discuss their various business activities.

The following abbreviations or acronyms are used by the Progress Registrants:

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings & Stock Ownership Plan
AFUDC	Allowance for funds used during construction
AHI	Affordable housing investment
ARO	Asset retirement obligation
Annual Average Price	Average wellhead price per barrel for unregulated domestic crude oil for the year
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Broad River	Broad River LLC's Broad River Facility
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCO	Competitive Commercial Operations
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Ceredo	Ceredo Synfuel LLC
CIGFUR	Carolina Industrial Group for Fair Utility Rates II
Clean Smokestacks Act	North Carolina Clean Smokestacks Act, enacted in June 2002
Coal Mining	Two Progress Fuels subsidiaries engaged in the coal mining business
Coal and Synthetic Fuels	Former business segment that had been primarily engaged in the production and sales of coal-based solid synthetic fuels, the operation of synthetic fuels facilities for third parties and coal terminal services
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Colona	Colona Synfuel Limited Partnership, LLLP
Corporate and Other	Corporate and Other segment includes Corporate as well as other nonregulated businesses
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's Crystal River Units No. 4 and 5 coal-fired steam turbines
CUCA	Carolina Utility Customers Association
CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DeSoto	DeSoto County Generating Co., LLC
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"
Dixie Fuels	Dixie Fuels Limited
DOE	United States Department of Energy

DSM	Demand-side management
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three are wholly owned
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause
EIA	Energy Information Agency
EIP	Equity Incentive Plan

EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERO	Electric reliability organization
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDCA	Florida Department of Community Affairs
FGT	Florida Gas Transmission Company
FIN 39	FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts"
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN 46R	FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143"
FIN 48	FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"
the Florida Global Case	U.S. Global, LLC v. Progress Energy, Inc. et al
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FSP	FASB Staff Position
FSP FIN 39-1	FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts"
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 business
the Georgia Contracts	Full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO
Georgia Power	Georgia Power Company, a subsidiary of Southern Company
Georgia Operations	Former reporting unit consisting of the Effingham, Monroe, Walton and Washington nonregulated generation plants in service and the Georgia Contracts
Global	U.S. Global, LLC
GridSouth	GridSouth Transco, LLC
Gulfstream	Gulfstream Gas System, L.L.C.
Harris	PEC's Shearon Harris Nuclear Plant
IBEW	International Brotherhood of Electrical Workers
IRS	Internal Revenue Service
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Level 3	Level 3 Communications, Inc.
LIBOR	London Inter Bank Offering Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in Part II, Item 7 of this Form 10-K
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured gas plant
MW	Megawatts
MWh	Megawatt-hours
Moody's	Moody's Investors Service, Inc.

NAAQS	National Ambient Air Quality Standards
NCDWQ	North Carolina Division of Water Quality
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
North Carolina Global Case	Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC
the Notes Guarantee	Florida Progress’ full and unconditional guarantee of the Subordinated Notes
NOx	Nitrogen Oxides
NOx SIP Call	EPA rule which requires 22 states including North Carolina, South Carolina and Georgia (but excluding Florida) to further reduce emissions of nitrogen oxides

NSR	New Source Review requirements by the EPA
NRC	United States Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
OPC	Florida's Office of Public Counsel
OPEB	Postretirement benefits other than pensions
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
PEF	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
PESC	Progress Energy Service Company, LLC
the Phase-out Price	Price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits are fully eliminated
PM 2.5	EPA standard for particulate matter less than 2.5 microns in diameter
PM 2.5-10	EPA standard for particulate matter between 2.5 and 10 microns in diameter
PM 10	EPA standard for particulate matter less than 10 microns in diameter
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 Affiliates	Five affiliated coal-based solid synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The 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
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PT LLC	Progress Telecom, LLC
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
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
QF	Qualifying facility
RCA	Revolving credit agreement
REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
Rowan	Rowan County Power, LLC
RSA	Restricted stock awards program
RSU	Restricted stock unit
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
Section 29	Section 29 of the Code

Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 316(b)	Section 316(b) of the Clean Water Act
Section 45K	Section 45K of the Code
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART II, Item 8 of this Form 10-K
SERC	SERC Reliability Corporation
SESH	Southeast Supply Header, L.L.C.
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. 115	Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS No. 123R	Statement of Financial Accounting Standards No. 123R, "Share-Based Payment"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative and Hedging Activities"
SFAS No. 141R	Statement of Financial Accounting Standards No. 141R, "Business Combinations"
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. 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements"
SFAS No. 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"
SFAS No. 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"
SFAS No. 160	Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51"
SNG	Southern Natural Gas Company
SO_2	Sulfur dioxide
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
Terminals	Coal terminals and docks in West Virginia and Kentucky
the Threshold Price	Price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits begin to be reduced
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
Winchester Production	Winchester Production Company, Ltd.
Winter Park	City of Winter Park, Fla.

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. 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.

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" (MD&A) including, but not limited to, statements under the following headings: a) "Strategy" about our future strategy and goals; b) "Results of Operations" about trends and uncertainties; c) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2010 and future financing plans; and d) "Other Matters" about our synthetic fuels tax credits, the effects of new environmental regulations, nuclear decommissioning costs and changes in the regulatory environment.

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 Energy Policy Act of 2005 (EPACT); the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the impact on our facilities and businesses from a terrorist attack; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; the Progress Registrants' ability to control costs, including operations and maintenance (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the ability to successfully access capital markets on favorable terms; the impact that increases in leverage may have on each of the Progress Registrants; 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; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); the investment performance of our nuclear decommissioning trust funds and assets of pension and benefit plans; 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 electric utility, primarily engaged in the regulated utility business. 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 incorporated on August 19, 1999 initially as CP&L Energy, Inc. and 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), a diversified, exempt electric utility holding company whose primary subsidiaries were 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. As a registered holding company, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005 (PUHCA 2005) 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. The Utilities have more than 21,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers 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 meeting the growth needs of our service territories and delivering reliable, competitively priced energy from a diverse portfolio of power plants.

Our former Coal and Synthetic Fuels segment was previously involved in nonregulated activities, including the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (the Code), the operation of synthetic fuels facilities for third parties as well as coal terminal services. Our terminal operations supported our synthetic fuels businesses for the procuring and processing of coal and the transloading and marketing of synthetic fuels. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities. The decision to idle production was based on the high level of oil prices and the resumption of synthetic fuels production was dependent upon a number of factors, including a reduction in oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. The operation of synthetic fuels facilities on behalf of third parties continued through late December 2007. We have ceased to use our majority-owned facilities, and in accordance with the provisions of Statement of Financial Accounting Standard (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), these assets are considered abandoned. Additionally, our other synthetic fuels operations ceased as of December 31, 2007, and we have signed an agreement to sell our coal terminals. Consequently, we reclassified the operations of our synthetic fuels businesses and coal terminal services as discontinued operations in the fourth quarter of 2007 (See Note 3B).

The Corporate and Other segment primarily includes the operations of the Parent and Progress Energy Service Company, LLC (PESC). It also includes miscellaneous nonregulated business areas that do not separately meet the quantitative disclosure requirements as a separate business segment. PESC provides centralized administrative, management and support services to our subsidiaries. See Note 18 for additional information about PESC services provided and costs allocated to subsidiaries.

As discussed in "Significant Developments" below, many of our nonregulated business operations have been divested or are in the process of being divested. See Note 19 for information regarding the revenues, income and assets attributable to our business segments.

For the year ended December 31, 2007, our consolidated revenues were $9.2 billion and our consolidated assets at year-end were $26.3 billion.

SIGNIFICANT DEVELOPMENTS

As discussed more fully in Note 3 and under MD&A – "Discontinued Operations," we divested, or announced divestitures, of multiple nonregulated businesses during 2007 and 2006 in accordance with our business strategy to reduce our business risk from nonregulated operations, to focus on the core operations of the Utilities and to reduce debt using cash proceeds from the divestitures. In 2007, we completed the divestiture of Competitive Commercial Operations (CCO), we abandoned our synthetic fuels businesses and entered into an agreement to sell our remaining coal mine and coal terminal services.

AVAILABLE INFORMATION

The Progress Registrants' annual reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, 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 Web site at 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 a Web site, www.sec.gov, containing reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

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

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

COMPETITION

RETAIL COMPETITION

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give the Utilities' retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. However, the Utilities compete with suppliers of other forms of energy in connection with their retail customers.

Although there is no pending legislation at this time, if the retail jurisdictions served by the Utilities become subject to deregulation, the recovery of "stranded costs" could become a significant consideration. 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 qualified 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.

Our largest stranded cost exposure is for PEF's purchased power commitments with QFs, under which PEF has future minimum expected capacity payments through 2036 of $4.7 billion (See Notes 22A and 22B). PEF was obligated to enter into these contracts under provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA). PEF continues to seek ways to address the impact of escalating payments under these contracts. However, the Florida Public Service Commission (FPSC) allows for full recovery of the retail portion of the cost of power purchased from QFs. PEC does not have significant future minimum expected capacity payments under their purchased power commitments with QFs.

EPACT repealed 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. On October 20, 2006, the FERC issued a final rule to implement a provision from EPACT that provides for termination of an electric utility's obligation to enter into new power purchase contracts with a QF if the FERC makes specific findings about the QF's access to competitive markets. The order establishes a rebuttable presumption that any utility located in areas covered by certain regional transmission organizations (RTOs) (neither PEC nor PEF are within these specified areas) will be relieved from the must-buy requirement with respect to QFs larger than 20 MW. With respect to other markets, and with respect to all QFs 20 MW or smaller, the utility bears the burden of showing that it qualifies for relief from the must-buy requirement. Any electric utility seeking relief from the must-buy requirements, regardless of location, must apply to the FERC for relief. If the must-buy requirement is terminated in an electric utility's service territory, QFs, state agencies, or others may later petition for reinstatement of the requirement if circumstances change. The final rule went into effect January 2, 2007. This new rule is not applicable to us at this time, but could become applicable if PEC's or PEF's service territories are covered by a RTO in the future.

WHOLESALE COMPETITION

The Utilities compete with other utilities for bulk power sales and for sales to municipalities and cooperatives.

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. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of the Utilities to retain current wholesale customers who have existing contracts with PEC or PEF.

EPACT contains key provisions affecting the electric power industry, including competition among generators of electricity. The FERC has implemented and is considering a number of related regulations to implement EPACT that may impact, among other things, requirements for reliability, QFs, transmission information availability, transmission congestion, security constrained dispatch, energy market transparency, energy market manipulation and behavioral rules. In addition to EPACT, other policies and orders issued by the FERC have supported increased competition within the electric generation industry. EPACT clarified and expanded the FERC's authority to assure that markets operate fairly without imposing new, mandatory intrusion on state authorities.

In February 2007, the FERC issued Order No. 890 adopting a final rule designed to 1) strengthen the pro forma open access transmission tariff (OATT) to ensure that it achieves its original purpose of remedying undue discrimination, 2) provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the FERC's enforcement and 3) increase transparency in the rules applicable to planning and use of the transmission system. One of the most significant revisions to the pro forma OATT relates to the development of consistent methodologies for calculating available transfer capability, which determines whether transmission customers can access alternative power supplies. Other significant revisions include: changes to the transmission planning process; reform of energy and generator imbalance penalties; adoption of a "conditional firm" component to long-term point-to-point transmission service and reform of existing requirements for the provision of redispatch service; reform of rollover rights policy; clarification of tariff ambiguities; and increased transparency and customer access to information.

As a transmission provider with an OATT on file with the FERC, PEC and PEF are required to comply with the requirements of the new rule. A major requirement of the new rule was to file a revised pro forma OATT on July 13, 2007. PEC and PEF each made the required FERC filing and are currently operating under the new tariff. On December 28, 2007, the FERC issued Order No. 890-A granting requests for rehearing and making clarifications to Order No. 890. All transmission providers with an OATT on file with FERC are required to comply with the Order

No. 890 requirements as affirmed and clarified in Order No. 890-A and must make a compliance OATT filing by March 17, 2008. PEC and PEF anticipate filing the required OATT filing within the deadline.

Certain details related to the rule, such as the precise methodology that will be used to calculate available transfer capability, remain to be determined, and thus it is difficult to make a determination of the overall effect of this new rule on the Utilities' transmission operations or wholesale marketing function. However, on a preliminary basis, the rule is not anticipated to have a significant impact on the Utilities' financial results. Nonetheless, the final rule includes a wide range of provisions addressing transmission services, and as the new tariff is implemented there is likely to be a significant impact on the Utilities' transmission operations, planning and wholesale marketing functions.

PEC and PEF are subject to regulation by the FERC with respect to transmission service, including generator interconnection service for facilities making sales for resale and wholesale sales of electric energy. On December 7, 2007, PEC and other major transmission-owning utilities in the Southeast submitted a proposal to FERC for a new regional grid planning process designed to meet FERC directives under Order No. 890 applicable to planning and use of the transmission system. The proposed grid planning process is subject to public comment. We cannot predict the outcome of this matter.

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 PEC's control area and peninsular Florida. 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 PEC's control area and peninsular Florida.

We do not anticipate that the operations of the Utilities will be materially impacted by these market-based rates decisions.

REGIONAL TRANSMISSION ORGANIZATIONS

The FERC's Order 2000 established national standards for RTOs and advocated the view that regulated, unbundled transmission would facilitate competition in both wholesale and retail electricity markets. 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 GridSouth Transco, LLC (GridSouth). In July 2001, the FERC issued an order provisionally approving the GridSouth RTO. 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; no consensus was reached on creating a southeastern RTO. 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. On November 16, 2007, PEC petitioned the North Carolina Utilities Commission (NCUC) to allow it to establish a regulatory asset account for PEC's development costs for GridSouth. In 2007, the NCUC issued an order for one of the other GridSouth partners and ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. Consequently, PEC reduced its investment in GridSouth in 2007 by recording an $11 million charge to amortization expense, which represents amortization of the North Carolina portion of development costs since June 2002. PEC's recorded investment in GridSouth totaled $22 million at December 31, 2007. We cannot predict the outcome of this matter.

PEF participated in the GridFlorida RTO for peninsular Florida. A cost-benefit study performed by an independent consulting firm concluded that the GridFlorida RTO was not beneficial to jurisdictional customers. Subsequently, during 2006 the GridFlorida docketed proceedings were closed by both the FPSC and the FERC, and GridFlorida was dissolved. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

FRANCHISE MATTERS

PEC has nonexclusive franchises with varying expiration dates in most of the municipalities in North Carolina and South Carolina in which it distributes electricity. In North Carolina, franchises generally continue for 60 years. In South Carolina, franchises continue in perpetuity unless terminated according to certain statutory methods. 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, the majority covers 60-year periods from the date enacted, and 45 have no specific expiration dates. Of the franchise agreements with expiration dates, 23 expire during the period 2008 through 2012, and the remaining agreements expire between 2013 and 2061. PEC also provides service within a number of municipalities and in all of the unincorporated areas without franchise agreements within its service area.

PEF has nonexclusive franchises with varying expiration dates in 111 of the Florida municipalities in which it distributes electricity. PEF also provides service to 10 other municipalities and in all of the unincorporated areas without franchise agreements within its service area. 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. The franchise agreements cover periods ranging from 10 to 30 years with the majority covering 30-year periods from the date enacted. Of the 111 franchise agreements, 32 expire between 2008 and 2012, and the remaining agreements expire between 2013 and 2037.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

Effective February 8, 2006, EPACT provisions enacted PUHCA 2005. Progress Energy is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to the issuance and sale of securities, the establishment of intercompany extensions of credit, sales, acquisitions of securities and utility assets, and services performed by PESC. Under PUHCA 2005, the FERC also has authority over accounting and record retention and cost allocation jurisdiction at the election of the holding company system or the state utility commissions with jurisdiction over its utility subsidiaries.

UTILITY REGULATION

FEDERAL REGULATION

Other EPACT provisions included tax changes for the utility industry; incentives for emissions reductions; federal insurance and incentives to build new nuclear power plants; and certain protection for native retail load customers of load-serving entities. EPACT gave the FERC "backstop" transmission siting authority which provides for federal intervention, subject to limitations, when states are unable or unwilling to resolve transmission issues. EPACT also provided incentives and funding for clean coal technologies, provided initiatives to voluntarily reduce greenhouse gases and redesignated the Internal Revenue Code's (the Code's) Section 29 (Section 29) tax credit as a general business credit under the Code's Section 45K (Section 45K), which removed limits on synthetic fuels production and changed the carry forward period of the tax credits generated. 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 the DOE could impact the Utilities' system operations.

The FERC has adopted final rules implementing much of its broader authority under EPACT. These 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; prohibit market participants from intentionally or recklessly making any fraudulent or misleading statements with regard to transactions subject to the FERC's jurisdiction; and provide the procedures and rules for the establishment of an electric reliability organization (ERO) that will propose and enforce mandatory reliability standards for the bulk power electric system.

On July 20, 2006, the FERC certified the North American Electric Reliability Corporation (NERC) as the ERO. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards in particular regions of the country by entering into delegation agreements with regional entities. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

In Order 693, the FERC completed part of its EPACT implementation plan by approving 83 reliability standards developed by the NERC and set aside 24 standards pending further development. On June 18, 2007, compliance with the 83 FERC-approved reliability standards became mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. On December 20, 2007, the FERC approved three additional planning and operating reliability standards. Additionally, on January 17, 2008, the FERC approved eight mandatory critical infrastructure protection reliability standards to protect the bulk power system against potential disruptions from cyber security breaches. Prior to the FERC actions, electric utility industry compliance with the NERC standards had been voluntary.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Prior to the effective date of mandatory compliance with the reliability standards, PEC self-reported two noncompliances to SERC and PEF self-reported three noncompliances to FRCC. The FRCC, SERC and NERC have proposed that entities that self-reported noncompliance prior to the effective date and pursue aggressive mitigation plans will not be assessed fines. Subsequent to the effective date, PEC self-reported to the SERC three noncompliances with voluntary standards and PEF self-reported to the FRCC one noncompliance with voluntary standards and one noncompliance with a mandatory standard. PEC and PEF have submitted mitigation plans to SERC and FRCC, respectively, to address the self-reported noncompliance. Neither the noncompliances noted above nor the costs of executing the mitigation plans are expected to have a significant impact on our overall compliance efforts, results of operations or liquidity.

The Utilities are also subject to regulation by other federal regulatory agencies, including the United States Nuclear Regulatory Commission (NRC) and the Environmental Protection Agency (EPA). The Utilities' nuclear generating units are regulated by the NRC under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974. The NRC is responsible for granting licenses for the construction, operation and retirement of nuclear power plants and subjects these plants to continuing review and regulation. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved.

STATE REGULATION

PEC is subject to regulation in North Carolina by the NCUC, and in South Carolina by the Public Service Commission of South Carolina (SCPSC). PEF is subject to regulation in Florida by the FPSC. The Utilities are regulated by their respective regulatory bodies with respect to, among other things, rates and service for electricity sold at retail; retail cost recovery of unusual or unexpected expenses, such as severe storm costs; and issuances of securities. 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 earn a reasonable rate of return on its invested capital, including equity.

Retail Rate Matters

Each of the Utilities' state utility commissions authorize retail "base rates" that are designed to provide the respective utility with the opportunity to earn a reasonable rate of return on its "rate base," or investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of constructing, operating and maintaining the utility system, except those covered by specific cost-recovery clauses.

In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75 percent. The Clean Smokestacks Act enacted in North Carolina in 2002 (Clean Smokestacks Act) froze PEC's retail base rates in North Carolina through December 31, 2007, unless PEC experienced extraordinary events beyond the control of PEC, in which case PEC could have petitioned for a rate increase. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

During 2005, the FPSC approved a four-year base rate agreement with PEF. 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 the sole option to extend the agreement through the last billing cycle of June 2010. Pursuant to the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. PEF's base rate agreement also provides for revenue sharing between PEF and its ratepayers. For 2007, PEF agreed to refund two-thirds of retail base revenues between the $1.537 billion threshold and the $1.588 billion cap and 100 percent of revenues above the $1.588 billion cap. However, PEF's 2007 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. Both the threshold and cap are adjusted annually for rolling average 10-year retail kilowatt-hour (kWh) sales growth. Additionally, in 2008 the threshold and cap will be adjusted to add the revenue requirements of the generation facilities discussed above. For 2008, the threshold for revenue sharing will be $1.664 billion and the cap will be $1.716 billion.

Retail Cost-recovery Clauses

Each of the Utilities' state utility commissions 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 clause to a utility's base rates to reflect the approval of these costs and to reflect any past over- or under-recovery of costs. The Utilities do not earn a return on the recovery of eligible operating expenses under such clauses; however, in certain jurisdictions, the Utilities may earn interest on under-recovered costs. Additionally, the commissions may authorize a return for specified capital investments for energy efficiency and conservation, capacity costs, environmental compliance and utility plant. Fuel, fuel-related costs and certain purchased power 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 that helps mitigate the impact of cost increases in any one fuel. Due to the regulatory treatment of these costs and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of the Utilities, unless a commission finds a portion of such costs to have been imprudently incurred. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the timing of cash flow of the Utilities. See MD&A – "Regulatory Matters and Recovery of Costs" for additional discussion regarding cost-recovery clauses.

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

- €€*North Carolina Retail* – fuel costs, the fuel and other portions of purchased power (capacity costs for purchases from dispatchable QFs are also recoverable), costs of new demand-side management (DSM) and energy-efficiency programs and costs of reagents (commodities such as ammonia and limestone used in emissions control technologies);

- €€*South Carolina Retail* – fuel costs, certain purchased power costs, costs of reagents, sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission allowance expenses; and

- €€*Florida Retail* – fuel costs, purchased power costs, capacity costs, energy conservation expense and specified environmental costs, including SO_2 emission allowance expense and NOx compliance.

As discussed more fully in MD&A – "Other Matters – Regulatory Environment," eligible renewable energy costs and certain components of purchased power not previously recoverable through the fuel clause are recoverable in the North Carolina retail jurisdiction beginning in 2008.

Storm Recovery

In accordance with its base rate agreement, 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 O&M 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 its incurred storm restoration costs associated with the four hurricanes in 2004. The initial amount approved for recovery was based on PEF's estimate of costs and its impact was included in customer bills beginning August 1, 2005, as a storm surcharge. On September 12, 2005, PEF filed a true-up of an additional $19 million in costs, partially offset by $6 million of adjustments resulting from changes in allocation to the wholesale jurisdiction and refining the FPSC's 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. These costs were fully recovered at December 31, 2007.

During 2006, PEF entered into, and the FPSC approved, a settlement agreement with certain intervenors in its storm cost-recovery docket. The settlement agreement, as amended, allows PEF to extend its then-current two-year storm surcharge for an additional 12-month period. The extension, which began in August 2007, is expected to replenish the existing storm reserve by an estimated $126 million. Through December 31, 2007, PEF had recorded an additional $55 million of storm reserve from the extension of the storm surcharge. The amended settlement agreement provides that in the event future storms cause the reserve to be depleted, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

PEC does not maintain a storm damage reserve account and does not have an ongoing regulatory mechanism, such as a surcharge, 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 disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, nuclear plant operations, 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 2036, December 2034, October 2026 and July 2030, respectively. On November 14, 2006, PEC submitted an application to the NRC requesting a 20-year extension of the Harris operating license. The license renewal application for Harris is currently under review by the NRC with a decision expected in 2008.

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. PEF expects to submit an application requesting a 20-year extension of the operating license in the first quarter of 2009.

Since 2001, PEC and PEF have made various modifications to increase the output of their nuclear facilities. In January 2007, the FPSC approved PEF's petition to uprate CR3's gross output by approximately 180 MW. The multi-stage uprate is expected to increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification (See Note 7C).

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).

POTENTIAL NEW CONSTRUCTION

We previously announced that we are pursuing development of combined license (COL) applications to potentially construct new nuclear plants in North Carolina and Florida (See Item 1A "Risk Factors"). Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, a new plant would not be online until at least 2018.

On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. PEF expects to file the application for the COL in 2008. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, safety-related construction activities could begin as early as 2012, and a new plant could be online in 2016. In 2007, PEF completed the purchase of approximately 5,000 acres for the Levy County site which includes 1,845 acres available for future development and associated site specific transmission needs. PEF anticipates filing a Determination of Need petition with the FPSC in 2008.

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 approvals by the NRC, including the installation of on-site dry cask 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 their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pool through the expiration of its operating license, including its pending license extension.

See Note 22D for a discussion of the Utilities' contracts with the DOE for spent nuclear fuel.

DECOMMISSIONING

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

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. 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 frequently change and the ultimate costs of compliance cannot always be precisely estimated. The current estimated capital costs associated with compliance with pollution control laws and regulations that we expect to incur are included within MD&A – "Liquidity and Capital Resources – Capital Expenditures" and within MD&A – "Other Matters – Environmental Matters."

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North 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 10 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. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. While we accrue for probable costs that can be reasonably estimated, based upon the current status of some sites, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

See Note 21 and MD&A – "Other Matters – Environmental Matters" 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, 2008, we employed approximately 11,000 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 expires in December 2008. Contract negotiations are expected to begin in September 2008. The outcome of contract negotiations cannot be determined. We consider our relationship with employees, including those covered by collective bargaining agreements, to be good.

We have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees and an employee stock ownership 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, 2008, PEC and PEF employed approximately 5,000 and 4,000 full-time employees, respectively.

ELECTRIC – PEC

GENERAL

PEC is a regulated public utility 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, 2007, PEC had a total summer generating capacity (including jointly owned capacity) of 12,414 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 12,656 megawatt-hours (MWh) was set on August 9, 2007.

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, 2007, 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 percent of PEC's revenues.

PEC's segment profit was $498 million, $454 million and $490 million for the years ended December 31, 2007, 2006 and 2005, respectively. PEC's total assets were $11.962 billion and $12.020 billion as of December 31, 2007 and 2006, respectively.

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

	2007	2006	2005
Residential	**37%**	37%	37%
Commercial	**26%**	25%	24%
Wholesale	**18%**	18%	19%
Industrial	**17%**	18%	18%
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

	2007	2006	2005
Coal	**48%**	47%	47%
Nuclear	**42%**	43%	42%
Purchased power	**5%**	6%	6%
Oil/Gas	**4%**	3%	4%
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 and in Note 22A, 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)	**2007**	2006	2005
Coal	**$2.96**	$2.90	$2.72
Nuclear	**0.44**	0.43	0.42
Oil	**12.28**	11.04	8.60
Gas	**9.19**	9.87	10.90
Weighted-average	**2.21**	2.06	2.03

Changes in the unit price for coal, oil and gas are due to market conditions. Because 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 13 million tons of coal in 2008. Almost all of the coal will be supplied from Appalachian coal sources in the United States and will be primarily delivered by rail.

For 2008, PEC has short-term, intermediate and long-term agreements from various sources for approximately 94 percent of its estimated burn requirements of its coal units. The contracts have expiration dates ranging from one to ten years. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

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 nuclear fuel requirement needs for the foreseeable future. PEC's nuclear fuel contracts typically have terms ranging from three to ten years. For a discussion of PEC's plans with respect to spent fuel storage, see "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 combustion turbines that can operate with both oil and gas. The cost of

PEC's oil and gas is either at a fixed price or 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 under other contracts and utilizes interruptible transportation for its peaking load requirements.

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 225 MW. PEC submitted an application to relicense for 50 years its Tillery and Blewett Plants and anticipates a decision by the FERC in 2008. The Walters Plant license will expire in 2034.

Purchased Power

PEC purchased approximately 3.9 million MWh, 4.2 million MWh and 4.7 million MWh of its system energy requirements during 2007, 2006 and 2005, respectively, under purchase obligations and operating leases and had 1,381 MW of firm purchased capacity under contract during 2007. 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 in portions of Florida. At December 31, 2007, PEF had a total summer generating capacity (including jointly owned capacity) of 9,362 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 9,671 MWh on August 20, 2007.

PEF's service territory covers approximately 20,000 square miles in west central Florida, 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, 2007, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Reedy Creek Improvement District, Tampa Electric Company, and the cities of Bartow and Winter Park. PEF is subject to the rules and regulations of the FERC, the FPSC and the NRC. No single customer accounts for more than 10 percent of PEF's revenues.

PEF's segment profit was $315 million, $326 million and $258 million for the years ended December 31, 2007, 2006 and 2005, respectively. PEF's total assets were $10.004 billion and $8.593 billion as of December 31, 2007 and 2006, respectively.

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

	2007	2006	2005
Residential	**52%**	53%	52%
Commercial	**25%**	26%	25%
Wholesale	**9%**	7%	9%
Industrial	**7%**	8%	8%
Other retail	**7%**	6%	6%

Major industries in PEF's territory include phosphate rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other major 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

	2007	2006	2005
Oil/Gas	**32%**	31%	33%
Coal	**31%**	32%	33%
Purchased Power	**23%**	22%	21%
Nuclear	**14%**	15%	13%

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 and in Note 22A, 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)	**2007**	2006	2005
Oil	**$8.54**	$7.03	$5.90
Gas	**8.51**	7.41	8.53
Coal	**3.28**	3.16	2.70
Nuclear	**0.48**	0.50	0.51
Weighted-average	**4.85**	4.21	4.15

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

Coal

PEF anticipates a requirement of approximately 6 million tons of coal in 2008. Approximately 70 percent of the coal is expected to be supplied from Appalachian coal sources in the United States and 30 percent supplied from coal sources in South America. Approximately 55 percent of the coal is expected to be delivered by rail and the remainder by water. Prior to 2006, coal for PEF was supplied by Progress Fuels, a subsidiary of Progress Energy, pursuant to contracts between PEF and Progress Fuels. In 2006, PEF began entering into coal contracts on its own behalf.

For 2008, PEF has intermediate and long-term contracts with various sources for approximately 90 percent of the estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to ten years. 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 cost of PEF's oil and gas is either 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 and utilizes interruptible transportation to serve its peaking load requirements.

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 nuclear fuel requirement needs. PEF's nuclear fuel contracts typically have terms ranging from three to ten years. For a discussion of PEF's plans with respect to spent fuel storage, see "Nuclear Matters."

Purchased Power

PEF purchased approximately 11.1 million MWh, 10.4 million MWh and 9.9 million MWh of its system energy requirements during 2007, 2006 and 2005 respectively, under purchase obligations, operating leases and capital leases and had 3,229 MW of firm purchased capacity under contract during 2007. These agreements include approximately 965 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.

CORPORATE AND OTHER

Corporate and Other primarily includes the operations of the Parent and PESC. The Parent's unallocated interest expense is included in Corporate and Other. PESC provides centralized administrative, management and support services to our subsidiaries. Essentially all of the segment's revenues are due to PESC's services provided to our subsidiaries. See Note 18 for additional information about PESC services provided and costs allocated to subsidiaries. This segment also includes miscellaneous nonregulated business areas that do not separately meet the quantitative disclosure requirements as a separate business segment.

The Corporate and Other segment's loss was $120 million, $229 million and $225 million for the years ended December 31, 2007, 2006 and 2005, respectively. Corporate and Other segment total assets were $16.383 billion and $15.421 billion as of December 31, 2007 and 2006, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

	Years Ended December 31				
	2007	2006	2005	2004	2003
Energy supply (millions of kWh)					
Generated					
Steam	**51,163**	48,770	52,306	50,782	51,501
Nuclear	**30,336**	30,602	30,120	30,445	30,576
Combustion Turbines/Combined Cycle	**13,319**	11,857	11,349	9,695	7,819
Hydro	**415**	594	749	802	955
Purchased	**14,994**	14,664	14,566	13,466	13,848
Total energy supply (Company share)	**110,227**	106,487	109,090	105,190	104,699
Jointly owned share (a)	**5,351**	5,224	5,388	5,395	5,213
Total system energy supply	**115,578**	111,711	114,478	110,585	109,912
Average fuel cost (per million Btu)					
Fossil	**$ 4.54**	$ 4.17	$ 4.05	$ 3.17	$ 2.94
Nuclear fuel	**$ 0.45**	$ 0.44	$ 0.44	$ 0.44	$ 0.44
All fuels	**$ 3.17**	$ 2.86	$ 2.83	$ 2.21	$ 2.05
Energy sales (millions of kWh)					
Retail					
Residential	**37,112**	36,280	36,558	35,350	34,712
Commercial	**26,215**	25,333	25,258	24,753	24,110
Industrial	**15,721**	16,553	16,856	17,105	16,749
Other Retail	**4,805**	4,695	4,608	4,475	4,382
Wholesale	**21,239**	19,117	21,137	18,323	19,841
Unbilled	**33**	(371)	(440)	449	189
Total energy sales	**105,125**	101,607	103,977	100,455	99,983
Company uses and losses	**5,102**	4,880	5,113	4,735	4,716
Total energy requirements	**110,227**	106,487	109,090	105,190	104,699
Electric revenues (in millions)					
Retail	**$ 7,672**	$ 7,429	$ 6,607	$ 6,066	$ 5,620
Wholesale	**1,188**	1,039	1,103	843	914
Miscellaneous revenue	**273**	256	235	244	207
Total electric revenues	**$ 9,133**	$ 8,724	$ 7,945	$ 7,153	$ 6,741

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

REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2007	2006	2005	2004	2003
Energy supply (millions of kWh)					
Generated					
Steam	**30,770**	28,985	29,780	28,632	28,522
Nuclear	**24,212**	24,220	24,291	23,742	24,537
Combustion Turbines/Combined Cycle	**2,960**	2,106	2,475	1,926	1,344
Hydro	**415**	594	749	802	955
Purchased	**3,901**	4,229	4,656	4,023	4,467
Total energy supply (Company share)	**62,258**	60,134	61,951	59,125	59,825
Jointly owned share (a)	**4,800**	4,649	4,857	4,794	4,670
Total system energy supply	**67,058**	64,783	66,808	63,919	64,495
Average fuel cost (per million Btu)					
Fossil	**$ 3.50**	$ 3.37	$ 3.30	$ 2.52	$ 2.29
Nuclear fuel	**$ 0.44**	$ 0.43	$ 0.42	$ 0.42	$ 0.43
All fuels	**$ 2.21**	$ 2.06	$ 2.03	$ 1.57	$ 1.43
Energy sales (millions of kWh)					
Retail					
Residential	**17,200**	16,259	16,664	16,003	15,283
Commercial	**14,032**	13,358	13,313	13,019	12,557
Industrial	**11,901**	12,393	12,716	13,036	12,749
Other Retail	**1,438**	1,419	1,410	1,431	1,408
Wholesale	**15,309**	14,584	15,673	13,222	15,518
Unbilled	**(55)**	(137)	(235)	91	(44)
Total energy sales	**59,825**	57,876	59,541	56,802	57,471
Company uses and losses	**2,433**	2,258	2,410	2,323	2,354
Total energy requirements	**62,258**	60,134	61,951	59,125	59,825
Electric revenues (in millions)					
Retail	**$ 3,534**	$ 3,268	$ 3,133	$ 2,953	$ 2,824
Wholesale	**754**	720	759	575	687
Miscellaneous revenue	**96**	97	98	100	78
Total electric revenues	**$ 4,384**	$ 4,085	$ 3,990	$ 3,628	$ 3,589

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

REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2007	2006	2005	2004	2003
Energy supply (millions of kWh)					
Generated					
Steam	**20,393**	19,785	22,526	22,150	22,979
Nuclear	**6,124**	6,382	5,829	6,703	6,039
Combustion Turbines/Combined Cycle	**10,359**	9,751	8,874	7,769	6,475
Purchased	**11,093**	10,435	9,910	9,443	9,381
Total energy supply (Company share)	**47,969**	46,353	47,139	46,065	44,874
Jointly owned share (a)	**551**	575	531	601	543
Total system energy supply	**48,520**	46,928	47,670	46,666	45,417
Average fuel cost (per million Btu)					
Fossil	**$ 5.80**	$ 5.09	$ 4.88	$ 3.86	$ 3.63
Nuclear fuel	**$ 0.48**	$ 0.50	$ 0.51	$ 0.49	$ 0.50
All fuels	**$ 4.85**	$ 4.21	$ 4.15	$ 3.21	$ 3.07
Energy sales (millions of kWh)					
Retail					
Residential	**19,912**	20,021	19,894	19,347	19,429
Commercial	**12,183**	11,975	11,945	11,734	11,553
Industrial	**3,820**	4,160	4,140	4,069	4,000
Other Retail	**3,367**	3,276	3,198	3,044	2,974
Wholesale	**5,930**	4,533	5,464	5,101	4,323
Unbilled	**88**	(234)	(205)	358	233
Total energy sales	**45,300**	43,731	44,436	43,653	42,512
Company uses and losses	**2,669**	2,622	2,703	2,412	2,362
Total energy requirements	**47,969**	46,353	47,139	46,065	44,874
Electric revenues (in millions)					
Retail	**$ 4,138**	$ 4,161	$ 3,474	$ 3,113	$ 2,796
Wholesale	**434**	319	344	268	227
Miscellaneous revenue	**177**	159	137	144	129
Total electric revenues	**$ 4,749**	$ 4,639	$ 3,955	$ 3,525	$ 3,152

(a) Amounts represent joint 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 in general. 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 discussed current material risks, 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 multiple federal, state and local regulatory agencies, which significantly influences 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, siting and construction of facilities, 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. Laws and regulations frequently change and the ultimate costs of compliance cannot be precisely estimated. Such changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our financial performance depends on the successful operation of electric generating facilities by the Utilities and their ability to deliver electricity to customers.

Operating electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operational limitations imposed by environmental or other regulatory requirements;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes;
- interruptions to the supply of fuel and other commodities used in generation;
- compliance with mandatory reliability standards, including any subsequent revisions, for the bulk power electric system;
- inability to recruit and retain skilled technical workers;
- inadequate disposal capabilities for coal combustion byproducts; and
- catastrophic events such as hurricanes, floods, extreme drought, earthquakes, fires, explosions, terrorist attacks, pandemic health events such as avian influenza or other similar occurrences.

We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity that we sell to the retail and wholesale markets. 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.

In June 2007, compliance with initial FERC-approved reliability standards became mandatory. Additional standards were approved in December 2007 and January 2008 (See Item 1 "Business – Utility Regulation – Federal Regulation). We anticipate that more standards will be approved and that the standards will migrate to more definitive and enforceable requirements over time. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and penalties. If we are unable to meet the reliability standards for the bulk power electric system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Due to the prospects for construction of a number of new nuclear facilities across the country and an aging skilled workforce, there is increased competition within the energy sector for skilled technical workers for both the construction and operation of nuclear facilities. Our ability to successfully operate our nuclear facilities is dependent upon our continued ability to recruit and retain skilled technical workers.

Approximately 2,000 employees at PEF are represented by the IBEW. The three-year labor contract with the IBEW expires in December 2008. The outcome of contract negotiations cannot be determined, however, an unfavorable outcome could increase our operating costs.

Our coal plants produce coal combustion byproducts. The majority of our plants are nearing full capacity for disposal of coal combustion byproducts. As a result, we are developing new disposal plans for our coal plants, which will result in additional capital expenditures for construction of on-site disposal facilities and/or increased O&M costs for off-site disposal. Additionally, rulemakings at the state and federal levels have increased the risks associated with surface wastewater discharges and groundwater impacts, which could result in higher environmental compliance costs.

To operate our emission control equipment, we use significant quantities of ammonia and limestone. With mandated compliance deadlines for emission controls, demand for these reagents may increase and result in supply shortages. Decreased operational performance from the Utilities' generating facilities and delivery systems or increased costs of operating the facilities could have an adverse effect on our business and results of operations.

Meeting the anticipated growth in our service territories may require, among other things, the construction within the next decade of new gas and/or nuclear generation facilities and modernization of coal generation facilities to increase our generation capability and the siting and construction of associated transmission facilities. We may not be able to obtain required licenses, permits and rights-of-way; successfully and timely complete construction; or recover the cost of such new generation and transmission facilities through our base rates or other recovery mechanisms, any of which could adversely impact our financial condition, cash flows or results of operations.

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy-efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

Provisions for recovery of certain prudent compliance and new baseload generation construction costs were included in energy legislation passed by the North Carolina and South Carolina legislatures and in rules issued by the FPSC during 2007. The costs eligible for recovery could potentially be deemed to be imprudent by the respective states' utility commission.

The risks of each of the elements of our balanced solution include, but are not limited to, the following:

Energy-Efficiency and New Energy Resources

We are actively pursuing expansion of our energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. Our energy-efficiency program provides ways for customers to reduce energy use.

We are subject to the risk that our customers may not participate in our conservation programs or the forecasted results from these programs may be less than anticipated. This could result in our having to utilize greater levels of renewable energy resources to achieve the mandated REPS, discussed below, and require us to further expand our baseload generation or purchase additional power.

We are also subject to the risk that customer participation in these programs may decrease our revenues. With respect to energy efficiency and conservation, the FPSC has initiated a series of public workshops to gather information on how expansions to DSM programs may affect a utility's ability to recover adequate revenues. Although workshops have been held to date, the FPSC has not initiated any formal rulemaking process or policy changes regarding this issue, and it is uncertain what regulatory action may take place in the future.

We are actively engaged in a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources. These alternative energy projects may be determined to not be cost-efficient or cost-effective.

Modernization and Construction of Generating Plants

We are currently evaluating our options for new generating plants, including gas and nuclear technologies. At this time, no definitive decision has been made regarding the construction of nuclear plants. There is no assurance that we will be able to successfully and timely complete the projects to construct new generation facilities or to expand or modernize existing facilities within our projected budgets. These projects are long-term and may involve facility designs that have not been previously constructed or that have not been finalized at the time that project is commenced. Consequently, the projects potentially would be subject to significant cost increases for labor, materials, scope changes and changes in design. Should any such construction, expansion or modernization 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, expand or modernize generation and associated transmission facilities will be recoverable through our base rates or other recovery mechanisms.

The decision to build a new power plant will be based on several factors including:

- projected system load growth;
- performance of existing generation fleet;
- availability of competitively priced alternative energy sources;
- projections of fuel prices, availability and security;
- the regulatory environment;
- operational performance of new technologies;
- the time required to permit and construct;
- environmental impact;
- both public and policymaker support;
- siting and construction of transmission facilities;
- cost and availability of construction materials and labor;
- nuclear decommissioning costs, insurance, and costs of security;
- ability to obtain financing on favorable terms; and
- availability of adequate water supply.

The construction of a new power plant and associated expansion of our transmission system will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support the construction. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation facilities, but we cannot be certain we will be able to successfully negotiate any such arrangement. Furthermore, joint ventures or joint ownership arrangements also present risks and uncertainties, including those associated with sharing control over the construction and operation of a facility and reliance on the other party's financial or operational strength.

The demand for skilled construction labor is high across all industry sectors, resulting in increased labor costs and labor shortages. This impacts the ability to assure adequate work forces to maintain schedules with high quality construction at predictable costs. There is an increased demand worldwide for the components required for the manufacturing and construction of power plants. This has led to increased cost and lead times for materials and equipment. Additionally, there may be opposition to the development and construction of a power plant and/or the siting of associated transmission facilities, which can lead to delays in development or the necessity to abandon a preferred site.

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. Portions of our service territories have been impacted by the current downturn in the consumer credit and housing markets. The timing and extent of the recovery of the consumer credit and housing markets cannot be predicted. Additionally, our customers may undertake individual energy conservation measures, which could decrease the demand for electricity. If anticipated growth levels are not realized, we may increase our baseload capacity and have excess capacity. This excess capacity may exceed the 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.

Nuclear

In addition to the risks discussed above, the successful construction of a new nuclear power plant requires the satisfaction of a number of conditions. The conditions include, but are not limited to: the continued operation of the industry’s existing nuclear fleet in a safe, reliable, and cost-effective manner, an efficient and successful licensing process, continued public and policymaker support, and a viable program for managing spent nuclear fuel. We cannot provide certainty that these conditions will exist.

We previously announced that we are pursuing development of COL applications. Filing of a COL 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. We have selected a site in North Carolina and a site in Florida to evaluate for possible future construction of two additional nuclear units at each site. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. We currently expect to file an application for the COL for PEF’s site in 2008. For PEC, if we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2018. For PEF, if we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, construction activities could begin as early as 2012, and a new plant could be online in 2016. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

EPACT provides for an annual tax credit of 1.8 cents/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 that have met the permitting, construction and placed-in-service milestones specified by EPACT and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. The credit allocation process among new nuclear plants has not been determined. Other utilities 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.

In addition, other COL applicants would be pursuing regulatory approval, permitting and construction at roughly the same time as we would. Consequently, there may be shortages of qualified individuals to design, construct and operate these proposed new nuclear facilities.

Gas

In addition to the risks discussed above, the successful construction of a gas-fired plant requires access to an adequate supply of natural gas. The gas pipeline infrastructure in eastern and western North Carolina is limited. New pipelines may need to be extended to the new plant locations, which introduces risks associated with a construction project not under our direct control. Natural gas supply limitations lead to the construction of power plants capable of operating on both natural gas and fuel oil as a back-up fuel. Both of these fuels are fossil fuels and emit greenhouse gases, which may be subject to future regulation. The equipment needed for the construction of a natural gas power plant is in demand worldwide, which is negatively impacting the capability of the suppliers to deliver, leading to increased cost and longer lead times for the equipment.

Coal

In addition to the risks discussed above, the successful modernization of a coal-fired power plant requires the satisfaction of a number of conditions. As discussed further below, these include, but are not limited to, consideration of emissions of carbon dioxide (CO_2), NOx, SO_2 and mercury; an efficient licensing process; and disposal of coal combustion byproducts such as slag and fly ash. Emission control equipment requires the use of significant amounts of reagents, which may be in high demand with mandated compliance deadlines for emission controls.

We are subject to Renewable Energy Portfolio Standards (REPS) that may have a negative impact on our business, financial condition and results of operations .

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law establishes minimum REPS for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state's electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. The premium to be paid by electric utilities to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand is to be recovered through an annual clause. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations under the REPS, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the REPS requirements if the NCUC determines it is in the public interest to do so.

The law allows the utility to meet a portion of the REPS with energy reductions achieved through energy-efficiency programs. Energy-efficiency programs include any program or activity implemented after January 1, 2007, that results in less energy being used to perform the same function. Through the year 2020, a utility can use energy- efficiency programs to satisfy up to 25 percent of the REPS; beginning in 2021, these programs may constitute up to 40 percent of the requirements. On October 26, 2007, the NCUC issued proposed rules for implementation of the law. PEC expects final rules to be issued by the end of the first quarter of 2008.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first Southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions.

Among other things, the executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007 that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from on-site renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity (net metering). The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry, and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008.

In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry, and emissions reduction targets that are similar to those contained in the governor's executive orders. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008.

In February, 2008, the FPSC voted to approve a net metering and interconnection rule that will allow customers to interconnect renewable energy devices with utility infrastructure in order to allow such customers to defray some or all of their electric energy consumption. The rule is applicable to renewable generation devices that are two MW or smaller. Under the new rule, customers using such devices are given full retail credit against their consumption for power that they generate. Any excess power that customers import onto the utility's system is credited to the customer's account on a monthly basis and, if not used, is paid out at the end of the calendar year at the utility's cost of generation rate. This final rule is expected to be in effect by the second quarter of 2008. PEF's existing meters do not have net metering capability and will need to be replaced for customers who interconnect renewable energy devices.

Additional proposals at the state and federal levels for renewable energy standards could require the Utilities to produce or buy a higher portion of their energy from renewable energy sources. Mandated state and federal standards could result in the use of renewable fuels that are not cost-effective in order to comply with requirements.

In response to legislative initiatives that became effective in 2007, we are actively engaged in energy-efficiency and conservation programs and a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources and currently partner with organizations throughout our service territories to support hydrogen, solar and other forms of renewable and alternative energy. We have invested in research for alternative energy sources that might subsequently be determined to not be cost-efficient or cost-effective, thus subjecting us to the risks of further expanding our generation or purchasing additional power on the open market at then-prevailing prices.

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 represented approximately 4,323 MW, or 20 percent, of our regulated generation capacity for the year ended December 31, 2007. In addition, we are exploring the possibility of expanding our nuclear generating capacity with two additional units at both PEC and PEF to meet future expected baseload generation needs. 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, limitations on amounts and types of insurance available, potential operational liabilities, 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, 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, set license conditions, shut down a nuclear unit, or take some combination of these actions, 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.

Our nuclear facilities have operating licenses that need to be renewed periodically. We anticipate successful renewal of these licenses. However, potential terrorist threats and increased public scrutiny of utilities could result in an extended process with higher licensing or compliance costs.

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 existing power plants and compliance plans with regard to new and existing power plants. 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. Failure to comply with applicable regulations might result in the imposition of fines and penalties by regulatory authorities. We cannot provide assurance that existing environmental regulations will not be revised or that new environmental regulations will not be adopted or become applicable to us. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from our ratepayers.

In addition, we may be deemed a responsible party for environmental clean up at sites identified by a regulatory body or private party. 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. We have been identified as a PRP at 10 former MGP sites (eight at PEC and two at PEF). We are also currently in the process of assessing potential costs and exposures at the Ward Transformer site, the Carolina Transformer site and other sites. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. No material claims are currently pending. While we accrue for probable costs that can be reasonably estimated, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

There are proposals and ongoing studies at the state (including North Carolina, South Carolina and Florida), federal and international levels to address global climate change that could result in the regulation of CO_2 and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to our operations. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. We have articulated principles that we believe should be incorporated into any global climate change policy. In 2007, we issued a corporate responsibility summary report, which discusses our actions and in 2006, we issued our report to shareholders regarding our assessment of global climate change and air quality risks and our mitigating actions. 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. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Environmental compliance regulations require reduction of emissions of NOx, SO_2 and mercury from coal-fired power plants. We expect that future capital expenditures required to meet the emission limits could be in excess of $700 million at PEC and in excess of $1.9 billion at PEF 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, net of recovery of costs through cost-recovery clauses, and reduce the generating capacity of our coal-fired plants. O&M expenses will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation of the emission control equipment will require the procurement of significant quantities of reagents, such as limestone and ammonia. PEC's reagent costs are eligible for recovery under North

Carolina and South Carolina energy laws passed in 2007. Future increases in demand for these items from other utility companies operating similar equipment could increase our costs associated with operating the equipment.

See Note 21 for additional discussion of environmental matters.

Because weather conditions directly influence the demand for, our ability to provide, and the cost of providing electricity, our results of operations, financial condition and cash flows can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather .

Weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our future overall operating results may fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions were mild. While we believe that the Utilities' markets complement each other during normal seasonal fluctuations, unusually mild weather could diminish our results of operations and harm our financial condition.

Sustained severe drought conditions could impact operations at our fossil and nuclear plants as these facilities use water for cooling purposes and in the operation of environmental compliance equipment. Hydroelectric generating plants represent approximately 2 percent of PEC's generation capacity and they have been impacted by the drought in the southeastern United States. Generation from these plants has been reduced to conserve lake water and maintain adequate water flows downstream from these facilities. Should drought conditions worsen, generation at PEC's hydroelectric facilities could be further reduced. PEF has no hydroelectric generating plants.

Furthermore, destruction caused by severe weather events, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can result in lost operating revenues due to outages; property damage, including downed transmission and distribution lines; and additional and unexpected expenses to mitigate storm damage.

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 damage sustained during severe weather events. While the Utilities have historically been granted regulatory approval to recover or defer the majority of significant storm costs incurred, the Utilities' storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If we cannot recover costs associated with future severe weather events in a timely manner, or in an amount sufficient to cover our actual costs, our financial conditions and results of operations could be materially and adversely impacted.

Under a regulatory order, PEF maintains a storm damage reserve account for major storms. Due to the significant costs incurred to recover from the damage sustained during the 2004 hurricane season, PEF's storm damage reserve accounts were depleted at December 31, 2005. During 2006, the FPSC approved a modified settlement agreement that extended PEF's existing two-year storm surcharge for retail ratepayers for an additional 12-month period ending in August 2008. The extension is expected to replenish PEF's storm reserve by an estimated $126 million. In the event future storms cause the reserve to be depleted, the modified settlement agreement provides for PEF to petition the FPSC for implementation of an interim retail surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors to the settlement agreement agreed not to oppose recovery of 80 percent of a future claimed deficiency but reserved the right to challenge the recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. 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, which could result in an extended recovery period. The wholesale transmission portion of the storm reserve will be recovered through the OATT tariff that began in January 2008 and will continue for approximately five years.

PEC does not maintain a storm damage reserve account and does not have an ongoing 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.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our customers as well as the demand and competitive state of the wholesale market.

The Utilities are impacted by the economic cycles of the customers we serve. For the year ended December 31, 2007, residential customers represented approximately 37 percent and 52 percent of PEC's and PEF's billed electric revenues, respectively. Consequently, as our service territories experience economic downturns, residential customer consumption patterns may change and our revenues may be negatively impacted. Additionally, our customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income or individual energy conservation efforts.

For the year ended December 31, 2007, commercial and industrial customers represented approximately 43 percent and 32 percent of PEC's and PEF's billed electric revenues, respectively. Consequently, if our commercial and industrial customers experience economic downturns, their consumption of electricity may drop and our revenues can be negatively impacted. We have experienced declining revenues from customers in the lumber and building material industry due to the current downturn in the residential housing and construction market. In recent years, PEC's sales to industrial customers have been affected by downturns in the textile and chemical industries.

For the year ended December 31, 2007, 18 percent and 9 percent 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 2004, the FERC issued orders concerning utilities' ability to sell wholesale electricity at market-based rates, including the adoption of two interim screens for assessing an applicant's potential generation market power for determining whether the applicant should be allowed to sell wholesale electricity at market-based rates. 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, 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. We do not anticipate that the operations of the Utilities will be materially impacted by these market-based rates decisions.

Increased commodity prices may adversely affect various aspects of the Utilities' operations as well as the Utilities' 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 commodities as a result of our ownership of energy-related assets. We have hedging strategies in place to mitigate fluctuations in commodity supply prices, but to the extent that we do not cover our entire exposure to commodity price fluctuations, or our hedging procedures do not work as planned, there can be no assurances that our financial performance will not be negatively impacted by price fluctuations. 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.

Volatility in market prices for fuel and power may result from, among other items:

- 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.

In addition, we anticipate significant capital expenditures for environmental compliance and baseload generation. The completion of these projects within established budgets is contingent upon many variables including the securing of labor and materials at estimated costs. Recently, certain construction commodities such as steel have experienced significant price increases due to worldwide demand. Furthermore, higher worldwide demand for copper used in our transmission and distribution lines has led to significant price increases. We are subject to the risk that cost overages may not be recoverable from ratepayers and our financial condition, results of operations or cash flows may be adversely impacted.

Prices for SO_2 emission allowance credits under the EPA's emission trading program fluctuate. 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.

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 and prudently manage costs to the satisfaction of regulators.

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. The Utilities' state utility commissions allow recovery of certain costs through various cost-recovery clauses. A portion of these future costs could potentially be deemed imprudent by the Utilities' respective commissions. There is also a delay between the timing of when such costs are incurred and when the costs are recovered from the ratepayers. This lag can adversely impact the cash flow of the Utilities and, consequently, our interest expense.

With the Utilities' expected increased expenditures for environmental compliance, baseload generation and higher commodity prices, we anticipate that the Utilities' operations will be subject to an even higher level of scrutiny from regulators, policymakers and ratepayers. State regulators may not allow PEC and PEF to increase future retail rates in the manner or to the extent requested or may seek to reduce or freeze retail rates.

PEC's five-year base rate freeze expired in December 2007. Beginning in 2008, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation. PEF currently operates under a base rate freeze, in which base rates can only be changed under certain circumstances. The costs incurred by PEC and PEF are not generally subject to being fixed or reduced by state regulators. 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 management of our costs.

As a holding company with no revenue-generating operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily the 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 due to us.

The Parent is a holding company and as such, has no revenue-generating operations of its own. The Parent's ability to meet its financial obligations associated with the debt service obligations on $2.6 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 the Utilities, and the ability of its subsidiaries to pay upstream dividends or to repay funds due 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. Should the Utilities not be able to pay dividends or repay funds due to the Parent, the Parent's ability to pay interest and dividends would be restricted.

Our business is dependent on our ability to successfully access capital markets on favorable terms. Limits on our access to capital may adversely impact our ability to execute our business plan, pursue improvements or make acquisitions that we would otherwise rely on for future growth .

Our cash requirements are driven by the capital-intensive nature of our Utilities. In addition to operating cash flows, we rely heavily on commercial paper and long-term debt. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy will be adversely affected. We believe that we will continue to have sufficient access to these financial markets based upon our current credit ratings. However, market disruptions beyond our control or a downgrade of our credit ratings could increase our cost of borrowing and may adversely affect our ability to access the financial markets.

Based on our current plans, which are subject to periodic review and change, we expect capital expenditures of $8.4 billion and debt maturities of $1.7 billion over the next three years. If we cannot fund these needs through normal operations or by accessing capital markets, our business plans, financial condition, results of operations or cash flows may be adversely impacted.

We issue commercial paper to meet short-term liquidity needs. In the latter half of 2007, the short-term credit markets tightened, resulting in higher interest rate spreads and shorter durations. Currently, the market has improved; however, there has been volatility on commercial paper spreads, as the supply of short-term commercial paper has increased following recent actions by the Federal Open Market Committee. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other options for meeting our short-term liquidity needs, which may include borrowing from our revolving credit agreements (RCAs), issuing short-term floating rate notes, and/or issuing long-term debt. These alternative sources of liquidity may not have comparable favorable terms and thus, may impact adversely our business plans, financial condition, results of operations or cash flows.

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 **.**

As discussed above, we rely heavily on our commercial paper and long-term debt. At December 31, 2007, 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)	$ 201	$ 2,597
PEC	–	3,183
PEF	–	2,686
Florida Progress Funding Corporation	–	271
Progress Energy, consolidated (b)	$ 201	$ 8,737

(a) Represents solely the outstanding indebtedness of the Parent.

(b) Net of current portion, which at December 31, 2007, was $877 million on a consolidated basis.

At December 31, 2007, we had an aggregate of three committed RCAs that supported our commercial paper programs totaling $2.030 billion. Our internal financial policy precludes us from issuing commercial paper in excess of our revolving credit lines. At December 31, 2007, we had $201 million reserved for outstanding commercial paper balance and a total amount of $19 million of letters of credit issued, leaving an additional $1.810 billion available for future borrowing under our revolving credit lines.

As described in Note 12, our credit agreements contain certain provisions and impose various limitations that could impact our liquidity, such as cross-default provisions and defined maximum total debt to total capital (leverage) ratios. Under these revolving credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on the Consolidated Balance Sheets.

As described in MD&A – "Strategy" and MD&A – "Future Liquidity and Capital Resources," we are anticipating extensive capital needs for new generation, transmission and distribution facilities, and environmental compliance expenditures. Funding these capital needs could increase our leverage and present numerous risks including those addressed below.

In the event our leverage increases such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs. Additionally, a significant 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 needed, 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 debt repayment thereby reducing funds available 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;
- requiring the issuance of additional equity;
- placing us at a competitive disadvantage compared to competitors who have less debt; and
- causing a downgrade in our credit ratings.

Changes in economic conditions could result in higher interest rates, which would increase interest expense on our floating rate debt, and reduce funds available to us for our current plans.

Any reduction in our credit ratings 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.

While the long-term target credit ratings for the Parent and the Utilities are above the minimum investment grade rating, we cannot provide certainty that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. 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. Any downgrade could increase our borrowing costs and may adversely affect our access to capital, which could negatively impact our financial results and business plans. 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 agency's rating should be evaluated independently of any other agency's rating.

Our ability to fully utilize tax credits generated under Section 29/45K may be limited. This risk is not applicable to PEC and PEF.

In accordance with the provisions of Section 29/45K, we have generated tax credits based on the content and quantity of synthetic fuels produced and sold to unrelated parties. This tax credit program expired at the end of 2007. We have received favorable private letter rulings from the Internal Revenue Service (IRS) on all of our synthetic fuels facilities. The timing of the utilization of the tax credits is dependent upon our taxable income, which can be impacted by a number of factors. Additionally, in the normal course of business, our tax returns are audited by the IRS. If our tax credits were disallowed in whole or in part as a result of an IRS audit, there could be significant additional tax liabilities and associated interest for previously recognized tax credits, which could have a material adverse impact on our earnings and cash flows. Although we are unaware of any currently proposed legislation or new IRS regulations or interpretations impacting previously recorded synthetic fuels tax credits, the value of credits generated could be unfavorably impacted by such legislation or IRS regulations and interpretations.

Market performance and other changes may decrease the value of nuclear decommissioning trust funds and benefit plan assets, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations to decommission the Utilities' nuclear plants and under our defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the assets may increase the funding requirements of the obligations to decommission the Utilities' nuclear plants and under our defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, the funding requirements of the obligations related to these benefit plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. If we are unable to successfully manage the nuclear decommissioning trust funds and benefit plan assets, our results of operation and financial position could be negatively affected.

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. These risks are not applicable to PEC and PEF .

We are exposed to operational risk resulting from our coal mining and terminal operations. 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. We actively manage the operational risks associated with these businesses. Nonetheless, adverse changes in operational issues beyond our control may result in losses in our earnings or cash flows and adversely affect our balance sheet.

As of December 31, 2007, our remaining coal mining operations have been idled. As discussed in Note 3G, on December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining and terminals operations businesses.

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 12,414 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2007, 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	Arden, N.C.	2	1964-1971	Coal	100	376	
Cape Fear	Moncure, N.C.	2	1956-1958	Coal	100	316	
Lee	Goldsboro, N.C.	3	1951-1962	Coal	100	399	
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	742	(b)
Robinson	Hartsville, S.C.	1	1960	Coal	100	176	
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.30(c)	2,443	(b)
Sutton	Wilmington, N.C.	3	1954-1972	Coal	100	598	
Weatherspoon	Lumberton, N.C.	3	1949-1952	Coal	100	173	
	Total	19				5,223	
COMBINED CYCLE							
Cape Fear	Moncure, N.C.	2	1969	Oil	100	70	
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100	466	
	Total	3				536	
COMBUSTION TURBINES							
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	335	
Blewett	Lilesville, N.C.	4	1971	Oil	100	52	
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	798	
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100	75	
Morehead City	Morehead City, N.C.	1	1968	Oil	100	12	
Richmond	Hamlet, N.C.	5	2001-2002	Gas/Oil	100	788	
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	15	
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100	59	
Wayne County	Goldsboro, N.C.	4	2000	Gas/Oil	100	679	
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	132	
	Total	41				2,945	
NUCLEAR							
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,875	(b)
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	112
	Total	15				225
TOTAL		82				12,414

(a) Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.

(b) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency’s share.

(c) PEC and Power Agency are joint owners of Unit 4 at the Roxboro Plant. PEC’s ownership interest in this 698 MW unit is 87.06 percent.

At December 31, 2007, including both the total generating capacity of 12,414 MW and the total firm contracts for purchased power of 1,381 MW, PEC had total capacity resources of approximately 13,795 MW.

Power Agency has undivided ownership interests of 18.33 percent in Brunswick Unit Nos. 1 and 2, 12.94 percent in Roxboro Unit No. 4, 3.77 percent in Roxboro Common facilities, and 16.17 percent in Harris and Mayo Unit No. 1. Otherwise, PEC has good and marketable title to its principal plants and 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, 2007, 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 20,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 12.5 million kilovolt-ampere (kVA) in approximately 2,400 transformers. Distribution line transformers numbered approximately 531,000 with an aggregate capacity of approximately 23 million 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 9,362 MW. Of this total, joint owners own approximately 117 MW. At December 31, 2007, 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	1,006
Bartow	St. Petersburg, Fla.	3	1958-1963	Gas/Oil	100	444
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,310
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	129
	Total	12				3,889
COMBINED CYCLE						
Hines	Bartow, Fla.	4	1999-2007	Gas/Oil	100	1,930
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	204
	Total	5				2,134
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	49
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	176
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	178
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	642
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	113
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	100 (b)	984 (c)
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	12
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	153
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	148
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,501
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	838 (c)
	Total	1				838
TOTAL		65				9,362

(a) Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.

(b) PEF and Georgia Power Company, a subsidiary of Southern Company (Georgia Power) are joint 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 2007, including both the total generating capacity of 9,362 MW and the total firm contracts for purchased power of 3,229 MW, PEF had total capacity resources of approximately 12,591 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22 percent. The joint ownership participants are: City of Alachua – 0.08 percent, City of Bushnell – 0.04 percent, City of Gainesville – 1.41 percent, Kissimmee Utility Authority – 0.68 percent, City of Leesburg – 0.82 percent, Utilities Commission of the City of New Smyrna Beach – 0.56 percent, City of Ocala – 1.33 percent, Orlando Utilities Commission – 1.60 percent and Seminole Electric Cooperative, Inc. – 1.70 percent. PEF and Georgia Power are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City Unit 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 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, 2007, 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 18,000 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 million kVA in approximately 700 transformers. Distribution line transformers numbered approximately 387,000 with an aggregate capacity of approximately 20 million kVA.

OTHER PROPERTIES

As discussed in Notes 3B and 3G, we have entered into an agreement to sell our remaining coal mining business and coal terminals that historically had been reported within the former Coal and Synthetic Fuels business segment. The coal mines are located in southeastern Kentucky and southwestern Virginia and have coal reserves of approximately 40 million tons of high quality, Central Appalachian coal. We ceased coal mining operations in the fourth quarter of 2007. The coal terminals facilities include a river terminal facility and a truck-to-truck facility in eastern Kentucky, a rail-to-barge facility on the Ohio River in West Virginia and three truck-to-barge facilities in West Virginia. We anticipate continuing to operate the coal terminal facilities until sold. These assets were reclassified to assets to be divested for financial reporting purposes.

The former Coal and Synthetic Fuels segment also historically reported interests in synthetic fuels entities located in West Virginia and Kentucky. In 2007, we permanently ceased production of synthetic fuels at these facilities. With the exception of one synthetic fuels facility that was located on leased property, our synthetic fuels facilities were located on property that will be included in the sale of the coal terminals.

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. See Note 22D for a discussion of certain other legal matters.

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
AS OF FEBRUARY 28, 2008

Name	Age	Recent Business Experience
William D. Johnson	53	**Chairman, President and Chief Executive Officer, Progress Energy, and Chief Executive Officer, Florida Progress,** October 2007 to present; President and Chief Operating Officer, Progress Energy, January 2005 to October 2007; Group President, PEC, May 2004 to October 2007; Executive Vice President, PEF, November 2000 to present; Executive Vice President, Florida Progress, November 2000 to May 2004; 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, Mr. Johnson was a partner with the Raleigh office of Hunton & Williams, where he specialized in the representation of utilities.
Peter M. Scott III	57	**Executive Vice President and Chief Financial Officer, Progress Energy,** May 2000 to December 2003; 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, 2000 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 A. Corbett	47	**Senior Vice President, PEC,** January 1, 2008 to present. Mr. Corbett oversees operations and services in the Carolinas, including engineering, distribution, construction, metering, power restoration, community relations, energy- efficiency, and alternative energy strategies. He previously served as Senior Vice President, PEF, June 15, 2006 to December 2007, with the same responsibilities in Florida as mentioned above. He served as Vice President-Distribution for PEC from January 2005 to June 2006. He also served PEC as Vice President-Eastern Region from September 2002 to January 2005, as well as Vice President, PEF from April 2005 to June 2006. Mr. Corbett joined Progress Energy in 1999 and has served Progress Energy in a number of roles, including General Manager of the Eastern Region and director of Distribution Power Quality and Reliability. Before joining Progress Energy, Mr. Corbett spent 17 years with Virginia Power, serving in a variety of engineering and leadership roles.
*Michael A. Lewis	45	**Senior Vice President, PEF,** January 2, 2008 to present. Mr. Lewis oversees operations and services in Florida, including engineering, distribution, construction, metering, power restoration, community relations, energy- efficiency, and alternative energy strategies. He previously served as Vice President of Distribution, PEF, from November 2000 to December 2007.
*Jeffrey J. Lyash	45	**President and Chief Executive Officer, PEF,** June 1, 2006 to present. Mr. Lyash oversees all aspects of PEF's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President of PEF from November 2003 through May 2006. 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 Brunswick in Southport, N.C. His last position at Brunswick was as Director of site operations.
John R. McArthur	51	**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 of PEC and Florida Progress, January 1, 2004 to present, and Senior Vice President, PEF and Progress Energy Service Company, LLC, December 2003 and December 2002, respectively, to present. He previously served as Corporate Secretary of FPC and PEC from January 1, 2004 to November 2007, Prior to his current position, 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.

Mark F. Mulhern	47	**Senior Vice President, Progress Energy and Progress Energy Service Company,** July 2007 to present. Mr. Mulhern oversees the strategic planning, treasury, utility finance and capital planning and control areas in the Financial Services Group. He is also Senior Vice President of PEC and PEF, from September 2007 to present, as well as President, Progress Energy Ventures, Inc. and Progress Fuels Corporation, March 2005 and April 2006, respectively, to present. Mr. Mulhern served Progress Energy Ventures, Inc. as Senior Vice President, Competitive Commercial Operations, from January 2003 to March 2005. He served Progress Energy Service Company as Vice President, Strategic Planning from November 2000 to January 2003. Mr. Mulhern also served as Vice President and Treasurer of PEC from June 1997 to November 2000.
James Scarola	51	**Senior Vice President and Chief Nuclear Officer, PEC and PEF,** January 2008 to present. Mr. Scarola oversees all aspects of our nuclear program. He previously served as Vice President at Harris from 1998 until 2005, when he moved to lead Brunswick until December 2007. Before joining Progress Energy in 1998, Mr. Scarola was plant general manager of Florida Power & Light Company's St. Lucie Power Station.
Paula J. Sims	45	**Senior Vice President**, **PEC and PEF,** April 2006 to present. Ms. Sims previously served PEC and PEF as Vice President-Fossil Generation from January 2006 to April 2006. Prior to that, she served PEC and PEF as Vice President-Regulated Fuels from December 2004 to December 2005. Ms. Sims served Progress Fuels Corporation as Chief Operating Officer from February 2002 to December 2004 and Vice President-Business Operations and Strategic Planning from June 2001 to February 2002. Prior to joining Progress Energy in 1999, Ms. Sims worked at General Electric for 15 years.
Jeffrey M. Stone	46	**Chief Accounting Officer and Controller, Progress Energy and FPC,** June 2005 to present; Chief Accounting Officer PEC and PEF, June 2005 and November 2005, respectively, to present; Vice President and Controller, Progress Energy Service Company, LLC, January 2005 and June 2005, respectively to present. Mr. Stone previously served as Controller of PEF and PEC from June 2005 to November 2005. 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.

Lloyd M. Yates	46	**President and Chief Executive Officer, PEC,** July 2007 to present. Mr. Yates oversees all aspects of the Carolinas delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President, PEC, January 2005 to July 2007. Mr. Yates was 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 November 1998 to November 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.

*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**
2007			
First Quarter	**$51.60**	**$47.05**	**$0.610**
Second Quarter	**52.75**	**45.15**	**0.610**
Third Quarter	**49.48**	**43.12**	**0.610**
Fourth Quarter	**50.25**	**44.75**	**0.615**
2006			
First Quarter	$45.31	$42.54	$0.605
Second Quarter	45.16	40.27	0.605
Third Quarter	46.22	42.05	0.605
Fourth Quarter	49.55	44.40	0.610

The December 31 closing price of our Common Stock was $48.43 for 2007 and $49.08 for 2006. As of February 22, 2008, we had 58,991 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, so long as no shares of preferred stock are outstanding. Our subsidiaries have provisions restricting dividends in certain limited circumstances (See Notes 10A and 12B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2008 Annual Meeting of Shareholders.

Issuer purchases of equity securities for fourth quarter of 2007 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1) (2)	(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	186,845	$47.1178	N/A	N/A
November 1 – November 30	–	–	N/A	N/A
December 1 – December 31	–	–	N/A	N/A
Total	186,845	$47.1178	N/A	N/A

(1) At December 31, 2007, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.

(2) 186,845 shares were purchased in open-market transactions by the plan administrator to satisfy share delivery requirements under the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) (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 neither issued nor 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 has neither issued nor repurchased any equity securities since becoming an indirect subsidiary of the Parent. During 2006, 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. During 2007 and 2005, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 10A and 12B). PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED FINANCIAL DATA

The selected 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)	**2007**	2006 (a)	2005 (a)	2004 (a)	2003 (a)
Operating results					
Operating revenues	**$ 9,153**	$ 8,724	$ 7,948	$ 7,168	$ 6,775
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**693**	551	523	552	536
Net income	**504**	571	697	759	782
Per share data					
Basic earnings					
Income from continuing operations	**$ 2.71**	$ 2.20	$ 2.12	$ 2.28	$ 2.26
Net income	**1.97**	2.28	2.82	3.13	3.30
Diluted earnings					
Income from continuing operations	**2.70**	2.20	2.12	2.27	2.25
Net income	**1.96**	2.28	2.82	3.12	3.28
Assets	**$ 26,286**	$ 25,707	$ 27,066	$ 26,013	$ 26,198
Capitalization and Debt					
Common stock equity	**$ 8,422**	$ 8,286	$ 8,038	$ 7,633	$ 7,444
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**84**	10	36	29	24
Long-term debt, net (b)	**8,737**	8,835	10,446	9,521	9,693
Current portion of long-term debt	**877**	324	513	349	868
Short-term debt	**201**	–	175	684	4
Capital lease obligations	**247**	72	18	19	20
Total capitalization and debt	**$ 18,661**	$ 17,620	$ 19,319	$ 18,328	$ 18,146
Dividends declared per common share	**$ 2.45**	$ 2.43	$ 2.38	$ 2.32	$ 2.26

(a) Operating results and balance sheet data have been restated for discontinued operations.

(b) Includes long-term debt to affiliated trust of $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005, 2004 and 2003 (See Note 23).

PEC

(in millions)	Years Ended December 31 2007	2006	2005	2004	2003
Operating results					
Operating revenues	**$ 4,385**	$ 4,086	$ 3,991	$ 3,629	$ 3,600
Net income	**501**	457	493	461	482
Earnings for common stock	**498**	454	490	458	479
Assets	**$ 11,962**	$ 12,020	$ 11,502	$ 10,787	$ 10,938
Capitalization and Debt					
Common stock equity	**$ 3,779**	$ 3,390	$ 3,118	$ 3,072	$ 3,237
Preferred stock – not subject to mandatory redemption	**59**	59	59	59	59
Long-term debt, net	**3,183**	3,470	3,667	2,750	3,086
Current portion of long-term debt	**300**	200	–	300	300
Short-term debt (a)	**154**	–	84	337	29
Capital lease obligations	**17**	18	18	19	20
Total capitalization and debt	**$ 7,492**	$ 7,137	$ 6,946	$ 6,537	$ 6,731

(a) Includes notes payable to affiliated companies, related to the money pool program, of $154 million, $11 million, $116 million and $25 million at December 31, 2007, 2005, 2004, and 2003, 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).

The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) 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," "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. Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. 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 following MD&A 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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" for a discussion of the factors that may impact any such forward-looking statements made herein.

MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements.

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments and their primary operations include:

- PEC – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina; and
- PEF – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida.

The "Corporate and Other" segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses that do not separately meet the quantitative requirements as a separate business segment.

STRATEGY

We are an integrated energy company primarily focused on the end-use electricity markets. Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. Our two electric utilities operate in regulated retail utility markets in the southeastern United States and have access to robust wholesale markets in the eastern United States, which we believe positions us well for long-term growth. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" for a discussion of the factors that may impact any such forward-looking statements made herein.

We are focused on the following key priorities:

- consistently excelling in the daily fundamentals of our utility business, including safely and reliably generating and delivering power to our customers;
- successfully implementing our balanced solution to responsibly address demand growth and climate change;
- maintaining constructive regulatory relations; and
- achieving our financial objectives year after year.

The Utilities operate in the southeastern United States, one of the fastest-growing regions of the country, and had a net increase of approximately 51,000 customers over the past year. Despite our anticipated customer growth, the Utilities are subject to economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets. Under normal weather conditions, we anticipate approximately 1.5 percent to 2.0 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.0 percent to 2.5 percent annual retail kWh sales growth at PEF in 2008. The Utilities seek a mix of 80 percent retail and 20 percent wholesale. The Utilities are focused on maintaining their regulated wholesale business through targeted contract renewals and origination opportunities.

We are implementing a comprehensive plan to meet the anticipated demand in the Utilities' service territories by focusing on energy efficiency, alternative energy and state-of-the-art power generation. First, we are enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. Recent legislation in North Carolina and Florida provides recovery for eligible costs of these programs. Second, we are pursuing renewable and alternative energy to increase the proportion of renewable and alternative energy sources in our generation portfolio. Recent legislation in North Carolina established a minimum renewable energy portfolio standard beginning in 2012. Executive orders issued by the governor of Florida address the reduction of greenhouse gas emissions and may lead to renewable energy standards in Florida. The Utilities have requested proposals for alternative energy sources, and options being considered include conversion of waste (such as wood, scrap tires and landfill gas) to energy, biomass as well as investments in solar and fuel cell programs. Third, we are evaluating new generation and fleet upgrades as we estimate that we will require new baseload generation facilities at both PEC and PEF toward the end of the next decade. We are evaluating the best available options for new generation, including advanced design nuclear technology, gas-fired combined cycle and combustion turbines, and modernization of existing coal plants to use clean coal technology. The considerations that will factor into this decision include, but are not limited to, construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing.

On February 19, 2008, PEC filed its combined license (COL) application with the NRC for two additional reactors at Harris. We anticipate filing a COL application in 2008 to potentially construct new nuclear plants in Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. If we decide to pursue nuclear expansion, favorable changes in the regulatory and construction processes have evolved in recent years, including standardized design, detailed design before construction, COL to build and operate, streamlined regulatory approval process, annual prudence reviews and cost-recovery mechanisms for pre-construction and financing costs. State regulatory processes are specific to each jurisdiction. Also, nuclear generation has recently gained greater public support as a reliable energy source that does not emit greenhouse gases. See "Other Matters – Nuclear Matters" for additional information.

We are subject to significant air quality regulations passed in 2005 by the United States Environmental Protection Agency (EPA) that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR) and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule (CAMR)). Additionally, at PEC's coal-fired facilities in North Carolina, we are subject to the North Carolina Clean Smokestacks Act enacted in 2002 (Clean Smokestacks Act). Including estimated costs for CAIR, CAVR, mercury regulation and the Clean Smokestacks Act, we currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or pass-through clauses, could be in excess of $700 million at PEC and $1.9 billion at PEF through 2018, which corresponds to the latest emission reduction deadline. In addition, growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time.

The Utilities successfully resolved key state regulatory issues in 2007, including retail fuel recovery filings in all jurisdictions. PEF also received Federal Energy Regulatory Commission (FERC) approval of its revised Open Access Transmission Tariff (OATT), including a settlement agreement with major transmission customers. In addition to Florida energy legislation enacted in 2006 that included cost-recovery mechanisms supportive of nuclear expansion, North Carolina and South Carolina both enacted energy legislation in 2007. North Carolina's comprehensive energy bill included provisions for expanding the traditional fuel clause, renewable energy portfolio standards, recovery of qualified DSM/efficiency programs and cost recovery during baseload generation construction. Key elements of South Carolina's energy law included expansion of the annual fuel clause and recovery mechanisms and streamlined regulatory processes supportive of nuclear expansion. As part of the Clean Smokestacks Act, PEC operated under a base rate freeze in North Carolina through 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. As a result of its 2005 base rate proceeding, PEF's base rate settlement extends through 2009. See "Other Matters – Regulatory Environment" and Note 7 for further information.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 20 consecutive years, and 32 of the last 33 years. We plan to continue our efforts to enhance balance sheet strength and flexibility so that we are positioned to accommodate the significant future growth expected at the Utilities. As of the end of 2007, our debt to total capitalization ratio was 53.3 percent. Our targeted debt to total capitalization ratio is 55 percent.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the 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, and the timing of recovery of fuel costs and storm damage. The Utilities contributed $813 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2007. Partially offsetting the Utilities' segment profit contribution were losses of $120 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While the Utilities expect retail sales growth in the future, they are facing, and expect to continue to face, rising costs. The Utilities remain committed to minimizing the expected growth in operation and maintenance (O&M) expenses by effectively managing costs. 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 as 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.

We expect total capital expenditures (including expenditures for environmental compliance) for 2008, 2009 and 2010 to be approximately $2.8 billion, $2.9 billion and $2.8 billion, respectively. Subject to regulatory approval, applicable capital investments to support load growth and comply with environmental regulations increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized, and create the basis for long-term earnings growth in the Utilities.

We expect to fund our business plans and new generation through operating cash flows and a combination of long-term debt, preferred stock and common equity, all of which are dependent on our ability to successfully access capital markets. We may also pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

Our synthetic fuels operations have historically provided significant net earnings driven by the Section 29/45K tax credit program, which expired at the end of 2007. In accordance with our decision to permanently cease production of synthetic fuels, we abandoned our majority-owned facilities in the fourth quarter of 2007. The operations of our synthetic fuels businesses were reclassified to discontinued operations in 2007. However, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred Section 29/45K tax credits generated through December 31, 2007, but not yet utilized, are ultimately utilized. At December 31, 2007, the amount of these deferred tax credits carried forward was $830 million. See "Other Matters – Synthetic Fuels Tax Credits" below, Note 22D and Item 1A, "Risk Factors" for additional information on our synthetic fuels tax credits and other matters.

As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, the majority of our nonregulated business operations have been divested or are in the process of being divested. These operations have been classified as discontinued operations in the accompanying financial statements. Consequently, the composition of other continuing segments has been impacted by these divestitures.

The Progress Registrants are subject to various risks. For a discussion of their current material risks, see 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 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

For the year ended December 31, 2007, our net income was $504 million or $1.97 per share compared to $571 million or $2.28 per share for the same period in 2006. For the year ended December 31, 2007, our income from continuing operations was $693 million compared to $551 million for the same period in 2006. The increase in income from continuing operations as compared to prior year was due primarily to:

- lower Clean Smokestacks Act amortization expense at PEC;
- lower interest expense at the Parent due to reducing debt in late 2006;
- the cost incurred to redeem debt at the Parent in 2006;
- favorable weather at PEC;
- lower allocations of corporate overhead to continuing operations as a result of the 2006 divestitures;
- unrealized losses recorded on contingent value obligations (CVOs) during 2006;
- favorable allowance for funds used during construction (AFUDC) equity at the Utilities;
- favorable growth and usage at the Utilities; and
- higher wholesale sales at PEF.

Partially offsetting these items were:

- higher O&M expenses at the Utilities primarily due to higher outage and maintenance costs and higher employee benefits;
- additional depreciation expense associated with PEC’s accelerated cost-recovery program for nuclear generation assets (See Note 7B);
- higher interest expense at PEF;
- the impact of the 2006 gain on sale of Level 3 Communications, Inc. (Level 3) stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- higher other operating expenses due to disallowed fuel costs at PEF.

For the year ended December 31, 2006, our net income was $571 million or $2.28 per share compared to $697 million or $2.82 per share for the same period in 2005. For the year ended December 31, 2006, our income from continuing operations was $551 million compared to $523 million for the same period in 2005. The increase in income from continuing operations as compared to prior year was due primarily to:

- prior year postretirement and severance expenses related to the 2005 cost-management initiative;
- increased retail growth and usage at the Utilities;

- the gain on sale of Level 3 stock acquired as part of the divestiture of PT LLC; and

- the prior year write-off of unrecoverable storm costs at PEF.

Partially offsetting these items were:

- unfavorable weather at the Utilities;
- the cost incurred to redeem debt at the Parent;
- unrealized losses recorded on CVOs;
- increased nuclear outage expenses at PEC; and
- the prior year gain on the sale of PEF's utility distribution assets serving the City of Winter Park, Fla. (Winter Park).

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

(in millions)	**2007**	Change	2006	Change	2005
PEC	**$498**	$44	$454	$(36)	$490
PEF	**315**	(11)	326	68	258
Total segment profit	**813**	33	780	32	748
Corporate and Other	**(120)**	109	(229)	(4)	(225)
Total income from continuing operations	**693**	142	551	28	523
Discontinued operations, net of tax	**(189)**	(209)	20	(153)	173
Cumulative effect of change in accounting principle, net of tax	**–**	–	–	(1)	1
Net income	**$504**	$(67)	$571	$(126)	$697

COST-MANAGEMENT INITIATIVE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. 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, of which $5 million has been reclassified to discontinued operations. We did not incur similar charges during 2007 or 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.

PROGRESS ENERGY CAROLINAS

PEC contributed segment profits of $498 million, $454 million and $490 million in 2007, 2006 and 2005, respectively. The increase in profits for 2007 as compared to 2006 is primarily due to lower Clean Smokestacks Act amortization, the favorable impact of weather and favorable retail customer growth and usage, partially offset by higher O&M expenses related to plant outage and maintenance costs and employee benefit costs and additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generating assets.

The decrease in profits for 2006 as compared to 2005 is primarily due to the unfavorable impact of weather, higher O&M expense related to nuclear outages, the impact of suspending the allocation of the Parent's income tax benefit not related to acquisition interest expense and 2006 capital project write-offs. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. These were partially offset by postretirement and severance expenses incurred in 2005 and favorable retail customer growth and usage.

The revenue tables below present the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel is defined as total electric revenues less fuel revenues. We and PEC consider revenues excluding fuel a useful measure to evaluate PEC's electric operations because fuel revenues primarily represent the recovery of fuel and a portion of purchased power expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We and PEC have included the analysis below as a complement to the financial information we provide in accordance with accounting principles generally accepted in the United States of America (GAAP). However, revenues excluding fuel is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

(in millions) Customer Class	**2007**	% Change	2006	% Change	2005
Residential	**$1,613**	10.3	$1,462	2.8	$1,422
Commercial	**1,107**	10.3	1,004	6.8	940
Industrial	**716**	0.7	711	3.9	684
Governmental	**98**	7.7	91	4.6	87
Total retail revenues	**3,534**	8.1	3,268	4.3	3,133
Wholesale	**754**	4.7	720	(5.1)	759
Unbilled	**–**	–	(1)	–	4
Miscellaneous	**96**	(2.0)	98	4.3	94
Total electric revenues	**4,384**	7.3	4,085	2.4	3,990
Less: Fuel revenues	**(1,524)**	–	(1,314)	–	(1,186)
Revenues excluding fuel	**$2,860**	3.2	$2,771	(1.2)	$2,804

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

(in thousands of MWh) Customer Class	**2007**	% Change	2006	% Change	2005
Residential	**17,200**	5.8	16,259	(2.4)	16,664
Commercial	**14,032**	5.0	13,358	0.3	13,313
Industrial	**11,901**	(4.0)	12,393	(2.5)	12,716
Governmental	**1,438**	1.3	1,419	0.6	1,410
Total retail energy sales	**44,571**	2.6	43,429	(1.5)	44,103
Wholesale	**15,309**	5.0	14,584	(6.9)	15,673
Unbilled	**(55)**	–	(137)	–	(235)
Total MWh sales	**59,825**	3.4	57,876	(2.8)	59,541

PEC's revenues, excluding fuel revenues of $1.524 billion and $1.314 billion for 2007 and 2006, respectively, increased $89 million. The increase in revenues was due primarily to the $57 million favorable impact of weather and a $22 million favorable impact of retail customer growth and usage. Weather had a favorable impact as cooling degree days were 20 percent higher than 2006. Cooling degree days were 16 percent higher than normal. The favorable retail customer growth and usage was driven by an approximate increase in the average number of customers of 28,000 as of December 31, 2007, compared to December 31, 2006.

Industrial electric energy sales decreased in 2007 compared to 2006 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a downturn in the lumber and building materials segment as a result of declines in residential construction. The increase in industrial revenues for 2007 compared to 2006 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

PEC's revenues, excluding fuel revenues of $1.314 billion and $1.186 billion for 2006 and 2005, respectively, decreased $33 million. The decrease in revenues was due primarily to the $67 million unfavorable impact of weather partially offset by a $24 million favorable impact of retail customer growth and usage. Weather had an unfavorable impact as cooling degree days were 9 percent below 2005 and heating degree days were 12 percent below 2005. The increase in retail customer growth and usage was driven by an approximate increase in the average number of customers of 29,000 as of December 31, 2006, compared to December 31, 2005. Although the change in wholesale revenue less fuel did not have a material impact on the change in revenues, wholesale electric energy sales were down 6.9 percent primarily due to lower excess generation sales in 2006 compared to 2005, partially offset by an increase in contracted wholesale capacity. The decrease in excess generation sales in 2006 compared to 2005 is due to favorable market conditions during 2005 that resulted in strong sales to the mid-Atlantic United States.

Industrial electric energy sales decreased in 2006 compared to 2005 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation. The increase in industrial revenues for 2006 compared to 2005 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

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 a portion of 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 from or refund to customers.

Fuel and purchased power expenses were $1.683 billion for 2007, which represents a $176 million increase compared to 2006. Fuel used in electric generation increased $208 million to $1.381 billion compared to 2006. This increase is primarily due to a $156 million increase in fuel used in generation and a $54 million increase in deferred fuel expense. Fuel used in generation increased primarily due to a change in generation mix as the percentage of generation supplied by natural gas increased in response to plant outages and higher system requirements driven by favorable weather. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. See “Electric – PEC – Fuel and Purchased Power” in Item 1, “Business” for a summary of average fuel costs. Purchased power expenses decreased $32 million to $302 million compared to prior year. The decrease in purchased power is due to lower cogeneration as a result of contract changes with one of PEC’s co-generators.

Fuel and purchased power expenses were $1.507 billion for 2006, which represents a $117 million increase compared to 2005. Fuel used in electric generation increased $137 million to $1.173 billion compared to 2005. This increase is due to a $141 million increase in deferred fuel expense partially offset by a $5 million decrease in fuel used in generation. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Fuel used in generation decreased primarily due to lower system requirements. Purchased power expenses decreased $20 million to $334 million compared to prior year. The decrease in purchased power is due primarily to a change in volume as a result of lower system requirements.

Operation and Maintenance

O&M expenses were $1.024 billion for 2007, which represents a $94 million increase compared to 2006. This increase is driven primarily by the $49 million higher plant outage and maintenance costs (partially due to three nuclear outages in the current year compared to only two in the prior year) and $29 million due to higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008.

O&M expenses were $930 million for 2006, which represents an $11 million decrease compared to 2005. This decrease is driven primarily by the $55 million impact of postretirement and severance expenses incurred in 2005 related to the cost-management initiative partially offset by $30 million of higher 2006 outage expenses at nuclear plants and capital project write-offs of $16 million in 2006.

Depreciation and Amortization

Depreciation and amortization expense was $519 million for 2007, which represents a $52 million decrease compared to 2006. This decrease is primarily attributable to a $106 million decrease in the Clean Smokestacks Act amortization, partially offset by $37 million additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets (See Note 7B), $11 million charge to reduce PEC's GridSouth Transco, LLC (GridSouth) regional transmission organization (RTO) development costs (See Note 7D) and the $7 million impact of depreciable asset base increases. We recorded $34 million of Clean Smokestacks Act amortization during 2007 compared to $140 million in 2006 (See Note 7B). We recorded $37 million of additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets during 2007 compared to none in 2006.

Depreciation and amortization expense was $571 million for 2006, which represents a $10 million increase compared to 2005. This increase is primarily attributable to the $12 million impact of depreciable asset base increases and $3 million of deferred environmental cost amortization partially offset by a $7 million decrease in the Clean Smokestacks Act amortization. We recorded $140 million of Clean Smokestacks Act amortization during 2006 compared to $147 million in 2005.

Taxes Other than on Income

Taxes other than on income were $192 million, $191 million and $178 million for 2007, 2006 and 2005, respectively. The $13 million increase in 2006 compared to 2005 is primarily due to a $7 million increase in property taxes and a $6 million increase in gross receipts taxes related to higher revenue. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expenses consisted of gains of $2 million and $10 million in 2007 and 2005, respectively, primarily due to land sales. There were no gains from land sales in 2006.

Total Other Income (Expense)

Total other income (expense) was $37 million of income for 2007, which represents a $13 million decrease compared to 2006. This decrease is primarily due to the 2006 reclassification of $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). This decrease is partially offset by $6 million favorable AFUDC equity related to costs associated with certain large construction projects.

Total other income (expense) was $50 million of income for 2006, which represents a $57 million increase compared to 2005. This increase is primarily due to the $32 million impact of reclassifying $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). Interest income increased $17 million for 2006 compared to 2005 primarily due to investment interest and interest on under-recovered fuel costs. In addition, the change in other income (expense) includes a $4 million favorable impact related to recording an audit settlement with the FERC in 2005.

Total Interest Charges, Net

Total interest charges, net were $210 million for 2007, which represents a $5 million decrease compared to 2006. This decrease is primarily due to the $5 million impact of a decrease in average long-term debt and $3 million favorable AFUDC debt related to costs associated with certain large construction projects, partially offset by $2 million higher interest related to higher variable rates on pollution control obligations.

Total interest charges, net were $215 million for 2006, which represents a $23 million increase compared to 2005. This increase is primarily due to the $20 million impact of a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $295 million, $265 million and $239 million in 2007, 2006 and 2005, respectively. The $30 million income tax expense increase in 2007 compared to 2006 is primarily due to the impact of higher pre-tax income. The $26 million income tax expense increase in 2006 compared to 2005 is primarily due to the allocation of $23 million of the Parent's tax benefit not related to acquisition interest expense in 2005 that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

PROGRESS ENERGY FLORIDA

PEF contributed segment profits of $315 million, $326 million and $258 million in 2007, 2006 and 2005, respectively. The decrease in profits for 2007 as compared to 2006 is primarily due to higher O&M expenses related to plant outage and maintenance costs and employee benefit costs, higher interest expense, higher other operating expenses and higher depreciation and amortization expense excluding recoverable storm amortization, partially offset by favorable AFUDC and higher wholesale sales.

The increase in profits for 2006 as compared to 2005 is primarily due to the impact of postretirement and severance costs incurred in 2005, favorable retail customer growth and usage, an increase in rental and other miscellaneous service revenues and the impact of the 2005 write-off of unrecoverable storm costs. These were partially offset by the 2005 gain on the sale of the utility distribution assets serving Winter Park, the unfavorable impact of weather on revenues and the impact of suspending the allocation of the Parent's tax benefit not related to acquisition interest expense. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

The revenue tables below present the total amount and percentage change of revenues excluding fuel and other pass-through revenues. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We and PEF consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We and PEF have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, revenues excluding fuel and other pass-through revenues is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

(in millions) Customer Class	2007	% Change	2006	% Change	2005
Residential	**$2,363**	0.1	$2,361	18.0	$2,001
Commercial	**1,153**	0.1	1,152	21.5	948
Industrial	**318**	(8.1)	346	21.8	284
Governmental	**304**	1.0	301	24.4	242
Revenue sharing refund	**–**	–	1	–	(1)
Total retail revenues	**4,138**	(0.6)	4,161	19.8	3,474
Wholesale	**434**	36.1	319	(7.3)	344
Unbilled	**4**	–	(5)	–	(6)
Miscellaneous	**173**	5.5	164	14.7	143
Total electric revenues	**4,749**	2.4	4,639	17.3	3,955
Less: Fuel and other pass-through revenues	**(3,109)**	–	(3,038)	–	(2,385)
Revenues excluding fuel and other pass-through revenues	**$1,640**	2.4	$1,601	2.0	$1,570

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

(in thousands of MWh) Customer Class	2007	% Change	2006	% Change	2005
Residential	**19,912**	(0.5)	20,021	0.6	19,894
Commercial	**12,183**	1.7	11,975	0.3	11,945
Industrial	**3,820**	(8.2)	4,160	0.5	4,140
Governmental	**3,367**	2.8	3,276	2.4	3,198
Total retail energy sales	**39,282**	(0.4)	39,432	0.7	39,177
Wholesale	**5,930**	30.8	4,533	(17.0)	5,464
Unbilled	**88**	–	(234)	–	(205)
Total MWh sales	**45,300**	3.6	43,731	(1.6)	44,436

PEF's revenues, excluding fuel and other pass-through revenues of $3.109 billion and $3.038 billion for 2007 and 2006, respectively, increased $39 million. The increase in revenues is primarily due to increased wholesale revenues, favorable retail customer growth and usage and other miscellaneous service revenues. Wholesale revenues increased $29 million primarily due to the $21 million impact of increased capacity under contract with a major customer. The favorable retail customer growth and usage impact of $7 million was driven by an approximate average net increase in the number of customers of 23,000 as of December 31, 2007, compared to December 31, 2006, partially offset by lower average usage per customer. Other miscellaneous service revenues increased primarily due to increased electric property rental revenues of $6 million.

Industrial electric energy revenues and sales decreased in 2007 compared to 2006 primarily due to a change in the terms of an agreement with a major customer.

PEF's revenues, excluding fuel and other pass-through revenues of $3.038 billion and $2.385 billion for 2006 and 2005, respectively, increased $31 million. The increase in revenues is due to a favorable retail customer growth and usage impact of $25 million and a $21 million increase in rental and other miscellaneous service revenues partially offset by a $13 million unfavorable impact of weather. The favorable retail customer growth and usage was driven by an approximate increase in the average number of customers of 35,000 as of December 31, 2006, compared to December 31, 2005. The weather impact is primarily due to a 16 percent decrease in heating degree days compared to 2005.

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 and capacity purchased in the market to meet customer load. Fuel, purchased power and capacity 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 from or refund to customers.

Fuel and purchased power expenses were $2.646 billion in 2007, which represents a $45 million increase compared to 2006. Purchased power expense increased $116 million to $882 million compared to 2006. This increase is primarily due to a $123 million increase in current year purchased power costs partially offset by a $6 million decrease in the recovery of deferred capacity costs. The increased current year purchased power costs are a result of higher interchange purchases of $87 million and higher capacity costs of $43 million primarily due to new contracts. Fuel used in electric generation decreased $71 million to $1.764 billion due to a $323 million decrease in deferred fuel expense partially offset by a $252 million increase in current year fuel costs due primarily to an increase in oil and natural gas prices. Deferred fuel expenses were higher in 2006 primarily due to the collection of fuel costs from customers that had been previously under-recovered. See "Electric – PEF – Fuel and Purchased Power" in Item 1, "Business" for a summary of average fuel costs.

Fuel and purchased power expenses were $2.601 billion in 2006, which represents a $584 million increase compared to 2005. Fuel used in electric generation increased $512 million due to a $552 million increase in deferred fuel expense resulting from an increase in the fuel recovery rates on January 1, 2006, as a result of fuel costs from customers that had been previously under-recovered. This was partially offset by a $41 million decrease in current year fuel costs due primarily to lower system requirements. Purchased power expense increased $72 million primarily due to a $48 million increase in current year purchased power costs resulting from higher market prices and a $23 million increase in the recovery of deferred capacity costs.

Operation and Maintenance

O&M expenses were $834 million in 2007, which represents a $150 million increase compared to 2006. The increase is primarily due to $46 million related to an increase in storm damage reserves from the one-year extension of the storm surcharge, which began August 2007 (See Note 7C) and $40 million related to higher environmental cost recovery (ECRC) and energy conservation cost recovery (ECCR) costs. Additionally, the increase is due to $27 million higher plant outage and maintenance costs and $12 million higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008. The ECRC, ECCR and storm damage reserve expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings.

O&M expenses were $684 million in 2006, which represents a $168 million decrease compared to 2005. The decrease is primarily due to a $102 million impact of postretirement and severance costs in 2005, $24 million of lower ECRC expenses due to a decrease in emission allowances and lower recovery rates, $17 million related to the 2005 write-off of unrecoverable storm restoration costs (See Note 7C), a $9 million decrease in nuclear outage costs and the $6 million impact related to the 2005 write-off of GridFlorida RTO startup costs that were previously recovered in revenues.

Depreciation and Amortization

Depreciation and amortization expense was $366 million for 2007, which represents a decrease of $38 million compared to 2006, primarily due to $47 million lower amortization of storm restoration costs and $5 million lower software and franchise amortization, partially offset by the $13 million impact primarily related to depreciable asset base increases and a $7 million write-off of leasehold improvements, primarily related to vacated office space. Storm restoration costs, which were fully amortized in 2007, were recovered through the storm recovery surcharge and, therefore, have no material impact on earnings (See Note 7C).

Depreciation and amortization expense was $404 million for 2006, which represents an increase of $70 million compared to 2005, primarily due to a $72 million increase in the amortization of storm restoration costs and a $48 million increase in utility plant depreciation partially offset by a $51 million decrease in expenses related to cost of removal primarily due to rate changes resulting from the 2005 depreciation study effective January 1, 2006 (See Note 5D). As noted above, storm restoration cost amortization has no material impact on earnings.

Taxes Other than on Income

Taxes other than on income were $309 million for 2007 and 2006, and $279 million for 2005. The $30 million increase in 2006 compared to 2005 is primarily due to $18 million of higher gross receipts taxes and $14 million of higher franchise taxes, related to an increase in revenues, partially offset by lower payroll taxes. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expenses were $8 million in 2007 compared to a gain of $2 million in 2006. The $10 million difference is primarily due to the $12 million impact of a Florida Public Service Commission (FPSC) order requiring PEF to refund disallowed fuel costs to its ratepayers (See Note 7C).

Other operating expenses were a gain of $2 million in 2006 compared to a gain of $26 million in 2005. The decrease in the gain for 2006 compared to 2005 is primarily due to the $24 million gain on the sale of the utility distribution assets serving Winter Park recorded in 2005 (See Note 7C).

Total Other Income

Total other income was $48 million for 2007, which represents a $20 million increase compared to 2006. This increase is primarily due to $24 million favorable AFUDC equity related to costs associated with large construction projects, partially offset by $5 million lower interest income on unrecovered storm restoration costs. We expect AFUDC equity to continue to increase in 2008, primarily due to increased spending on environmental initiatives and other large construction projects. See "Future Liquidity and Capital Resources – Capital Expenditures."

Total other income was $28 million for 2006, which represents a $20 million increase compared to 2005. This increase is primarily due to $8 million of increased investment interest income and $6 million of interest on unrecovered storm restoration costs.

Total Interest Charges, Net

Total interest charges, net were $173 million in 2007, which represents an increase of $23 million compared to 2006. The increase in interest charges is primarily due to the $10 million impact of an increase in average long-term debt, the $7 million impact of interest on over-recovered fuel costs, $6 million increase in interest on income tax related items and $2 million increase related to the disallowed fuel costs (See Note 7C). These increases are partially offset by $7 million favorable AFUDC debt related to costs associated with large construction projects.

Total interest charges, net were $150 million in 2006, which represents an increase of $24 million compared to 2005. The increase in interest charges is primarily due to the $20 million impact of a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $144 million, $193 million and $121 million in 2007, 2006 and 2005, respectively. The $49 million income tax expense decrease in 2007 compared to 2006 is primarily due to the $23 million impact of lower pre-tax income compared to the prior year, the $14 million impact of tax adjustments and the $9 million impact of favorable AFUDC equity discussed above. The tax adjustments are primarily related to the $11 million impact of changes in income tax estimates and the $3 million favorable impact related to the closure of certain federal tax years and positions. AFUDC equity is excluded from the calculation of income tax expense. The $72 million income tax expense increase in 2006 compared to 2005 is primarily due to changes in pre-tax income. In addition, 2005 income tax expense included the allocation of $13 million of the Parent's tax benefit not related to acquisition interest expense that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

CORPORATE AND OTHER

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. Corporate and Other expense is summarized below:

(in millions)		2007	Change	2006	Change	2005
Other interest expense	$	**(205)**	$ 54	$ (259)	$ (2)	$ (257)
Contingent value obligations		**(2)**	23	(25)	(31)	6
Tax reallocation		**–**	–	–	38	(38)
Other income tax benefit		**105**	(14)	119	19	100
Other expense		**(18)**	46	(64)	(28)	(36)
Corporate and Other after-tax expense	$	**(120)**	$ 109	$ (229)	$ (4)	$ (225)

Other interest expense, which includes elimination entries, decreased $54 million for 2007 compared to 2006 primarily due to the $86 million impact of the $1.7 billion reduction in debt at the Parent during 2006, partially offset by a $45 million decrease in the interest allocated to discontinued operations. The decrease in interest expense allocated to discontinued operations resulted from the allocations of interest expense in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $13 million and $58 million for 2007 and 2006, respectively.

Other interest expense, which includes elimination entries, increased $2 million for 2006 compared to 2005 primarily due to a $19 million decrease in the interest allocated to discontinued operations and a decrease in the elimination of intercompany interest expense due to lower intercompany debt balances partially offset by lower interest expense due to lower debt at the Parent. The decrease in interest expense allocated to discontinued operations resulted from the full year allocations of interest expense in 2005 compared to partial year allocations of interest in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $58 million and $77 million for 2006 and 2005, respectively.

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. At December 31, 2007, 2006 and 2005, the CVOs had a fair value of approximately $34 million, $32 million and $7 million, respectively. Progress Energy recorded unrealized losses of $2 million and $25 million for 2007 and 2006, respectively, and unrealized gains of $6 million for 2005, to record the changes in fair value of the CVOs, which had average unit prices of $0.35, $0.33 and $0.07 at December 31, 2007, 2006 and 2005, respectively.

For the years ended December 31, 2007 and 2006, income tax expense was not increased by the allocation of the Parent’s income tax benefits not related to acquisition interest expense to profitable subsidiaries. Due to the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), beginning in 2006 we no longer allocate the Parent income tax benefits not related to acquisition interest expense to profitable subsidiaries. Since 2002, Parent income tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a PUHCA 1935 order. For the year ended December 31, 2005, income tax expense was increased by $38 million due to the allocation of the Parent’s income tax benefit.

Other income tax benefit decreased for 2007 compared to 2006 primarily due to decreased pre-tax expense at the Parent primarily as a result of the loss on early retirement of debt in 2006, partially offset by the $14 million impact related to the closure of certain federal tax years and positions (See Note 14), the $18 million impact of taxes on interest allocated to discontinued operations and the $5 million impact related to the deduction for domestic production activities. Other income tax benefit increased for 2006 compared to 2005 primarily due to increased pre-tax expense at the Parent and the $8 million impact of taxes on interest allocated to discontinued operations.

For 2007, other expense was $18 million compared to $64 million in 2006. The $46 million decrease is primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent in 2006 (See Note 12) and the $30 million decrease in the allocation of corporate overhead as a result of the divestitures completed during 2006. These decreases are partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC in 2006 (See Note 3E) and the $14 million increase in interest income on temporary investments due to proceeds from the sale of nonregulated businesses. The $28 million increase in other expense from 2005 to 2006 was primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC. In addition, other expense changed due to a $14 million increase in interest income on temporary investments due to proceeds from the sale of DeSoto County Generating Co., LLC (DeSoto), Rowan County Power, LLC (Rowan) and our natural gas drilling and production business (Gas).

DISCONTINUED OPERATIONS

Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses to focus on the core operations of the Utilities. We divested, or announced divestitures, of multiple nonregulated businesses during 2007 and 2006. Consequently, the composition of other continuing segments has been impacted by these divestitures.

CCO OPERATIONS

CCO – Georgia Operations

On March 9, 2007, our subsidiary Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006 (See Note 3A).

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represents substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represents the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax. We used the net proceeds from these transactions for general corporate purposes.

CCO's operations generated net losses from discontinued operations of $283 million, $57 million and $54 million in 2007, 2006 and 2005, respectively. Net losses from discontinued operations in 2007 primarily represent the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to dedesignated natural gas hedges. These hedges were dedesignated because management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet of natural gas would be fulfilled. Therefore, cash flow hedge accounting was discontinued.

The increase in loss for 2006 compared to 2005 is primarily due to the $64 million pre-tax impairment loss ($42 million after-tax) on goodwill recognized in the first quarter of 2006 (See Note 8) and an increase in realized mark-to-market losses on gas hedges due to gas price volatility. This was partially offset by a higher gross margin related to serving the fixed price full requirements contracts that began in April 2005 and serving an increased load on a pre-existing contract in Georgia, and $66 million pre-tax of unrealized mark-to-market gains related to the dedesignated natural gas hedges.

CCO – DeSoto and Rowan Generation Facilities

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto and Rowan. DeSoto owned a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for a gross purchase price of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes (See Note 3D).

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006. DeSoto and Rowan operations generated combined net earnings from discontinued operations of $10 million and $3 million for the years ended December 31, 2006 and 2005, respectively.

TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously reported as a component of our former Coal and Synthetic Fuels operating segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes (See Note 3B).

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code. The production and sale of these products qualified for federal income tax credits under Section 29/45K so long as certain requirements were satisfied (See "Other Matters – Synthetic Fuels Tax Credits"). On September 14, 2007, we idled production of synthetic fuels at our majority-owned fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007 and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were "abandoned" and all operations ceased as of December 31, 2007. In accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets," a long-lived asset is abandoned when it ceases to be used. All periods have been restated to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Terminals and synthetic fuels businesses generated net earnings from discontinued operations of $83 million and $198 million for the years ended December 31, 2007 and 2005, respectively. Net losses from discontinued operations for Terminals and synthetic fuels businesses were $37 million for the year ended December 31, 2006.

The change in net loss from discontinued operations of $37 million for the year ended December 31, 2006, to net earnings from discontinued operations of $83 million for the year ended December 31, 2007, is primarily due to increased tax credits generated due to higher production of coal-based solid synthetic fuels, unrealized mark-to-market gain on derivative contracts in 2007 and the impairment of synthetic fuels assets recorded in 2006. These favorable items are partially offset by an increase in the tax credit reserve due to the increase in production and the change in the relative oil prices, which indicated a higher estimated phase-out of tax credits, and lower margins due to the increase in coal-based solid synthetic fuels production.

The change in net earnings from discontinued operations of $198 million for the year ended December 31, 2005, to net loss from discontinued operations of $37 million for the year ended December 31, 2006, is primarily due to lower synthetic fuels production as a result of high oil prices, which increased the potential phase-out of tax credits and the impairment of synthetic fuels assets recorded in 2006.

GAS OPERATIONS

On October 2, 2006, we sold Gas to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes (See Note 3C).

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

Gas operations generated net earnings from discontinued operations of $4 million, $82 million and $48 million for the years ended December 31, 2007, 2006 and 2005, respectively. The increase in net earnings from discontinued operations during 2006 is primarily due to increased production, higher market prices and mark-to-market gains on gas hedges.

PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of PT LLC to Level 3. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC (See Note 3E). See Note 20 for a discussion of the subsequent sale of the Level 3 stock in 2006.

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax gain on disposal of $28 million during the year ended December 31, 2006. Net (loss) earnings from discontinued operations for PT LLC were a loss of $2 million and earnings of $4 million for the years ended December 31, 2006 and 2005, respectively.

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications (See Note 3F).

Net earnings from discontinued operations for Dixie Fuels and other fuels business were $7 million and $5 million for the years ended December 31, 2006 and 2005, respectively.

COAL MINING BUSINESSES

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an estimated after-tax loss of $10 million for the sale of these assets (See Note 3G).

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va., and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves.

Net losses from discontinued operations for the coal mining business were $11 million, $4 million and $11 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PROGRESS RAIL

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. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. During the years ended December 31, 2006 and 2005, we recorded an estimated after-tax loss for the sale of these assets of $6 million and $25 million, respectively. Proceeds from the sale were used to reduce debt (See Note 3H).

Net earnings from discontinued operations for Progress Rail were $5 million for the year ended December 31, 2005.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We prepared our Consolidated Financial Statements in accordance with GAAP. 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 and Corporate Performance Committee (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' ratemaking processes 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 impairment indicators exist. Examples of these indicators include current period losses combined with a history of losses, a projection of continuing losses, a significant decrease in the market price of a long-lived asset group, or the likelihood that an asset group will be disposed of significantly prior to the end of its useful life. If an impairment 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 $16.612 billion at December 31, 2007. The carrying value of our total diversified business property, net is $6 million at December 31, 2007. In addition, we have certain diversified business property with a carrying value of $38 million at December 31, 2007, included in net assets to be divested (See Note 3I). 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.

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 performed this ceiling test calculation every quarter prior to the sale of the Gas Operations (See Note 3C). No write-downs were required in 2006 or 2005.

See discussion of synthetic fuels asset impairments in "Other Matters – Synthetic Fuels Tax Credits" and in Notes 8 and 9.

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 2007 and 2006, each of which indicated no impairment. If the fair values for the utility segments were lower by 10 percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2007 and 2006, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

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 and the selection of appropriate discount and growth rates. These underlying assumptions and estimates are made as of a point in time; subsequent changes, particularly changes in management’s estimate of future cash flows and the discount rates, growth rates or the timing of market equilibrium, could result in a future impairment charge to goodwill.

SYNTHETIC FUELS TAX CREDITS

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (See Note 3B). The production and sale of the synthetic fuels from these facilities qualified for tax credits under Section 29/45K if certain requirements were 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 2007, in accordance with federal legislation, 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 fuels production and subjects the credits to a 20-year carry forward period. This provision allowed us to produce synthetic fuels at a higher level than we have historically produced, had we chosen to do so. The synthetic fuels tax credit program expired at the end of 2007.

In addition, Section 29/45K provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeded a certain threshold value (the Threshold Price), the amount of tax credits was reduced for that year. Also, if the Annual Average Price increased high enough (the Phase-out Price), the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation. We estimate that the 2007 Annual Average Price will result in an approximate 70 percent phase-out of the synthetic fuels tax credits related to synthetic fuels production in 2007. This estimate is derived from our estimates of the 2007 Threshold Price and Phase-out Price of $57 per barrel and $71 per barrel, respectively, based on an estimated inflation adjustment for 2007. For 2007 synthetic fuels production, the 2007 Annual Average Price is not known until after the end of the year. We recorded the 2007 tax credits based on our estimates of what we believe the Annual Average Price will be for 2007. Any portion of the tax credits that were phased out based on the projected 2007 Annual Average Price exceeding the Threshold Price was not recorded.

See further discussion in “Other Matters – Synthetic Fuels Tax Credits” and Item 1A, “Risk Factors.”

PENSION COSTS

As discussed in Note 16A, we maintain 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 an increase 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 increased the discount rate to approximately 6.20% at December 31, 2007, from approximately 5.95% at December 31, 2006, which will decrease the 2008 benefit costs recognized, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Plan assets performed well in 2007, with returns of approximately 13%. That positive asset performance will result in decreased pension costs in 2008, all other factors remaining constant. In addition, contributions to pension plan assets in 2007 and 2008 will result in decreased pension costs in 2008 due to increased asset returns, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2008 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2008 will be $10 million to $20 million, compared with $31 million recognized in 2007.

We have pension plan assets with a fair value of approximately $2.0 billion at December 31, 2007. 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% change in the expected rate of return for 2007 would have changed 2007 pension costs by approximately $4 million.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is the method selected 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 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 holding company and, as such, has no revenue-generating operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $2.6 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities, and the ability of the Utilities to pay dividends or repay funds to us. As discussed under "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized. Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, primarily generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. 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 materially affect net income.

Effective February 8, 2006, the Energy Policy Act of 2005 (EPACT) provisions enacted the Public Utility Holding Company Act of 2005 (PUHCA 2005). Progress Energy is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to the issuance and sale of securities and 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. Pursuant to PUHCA 2005, 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.

Cash from operations, asset sales, short-term and long-term debt 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 2008. For the fiscal year 2008, we expect to realize an aggregate amount of approximately $100 million from the sale of stock through these plans.

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 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2007, 2006 and 2005. Net cash provided by operating activities for the three years ended December 31, 2007, 2006 and 2005, was $1.252 billion, $2.001 billion, and $1.467 billion, respectively.

Cash from operating activities for 2007 decreased when compared with 2006. The $749 million decrease in operating cash flow was primarily due to $472 million in income tax impacts, largely driven by income tax payments related to the sale of Gas; the $347 million payment made to exit the Georgia contracts (See Note 3A); a $279 million decrease in the recovery of fuel costs; and $65 million in premiums paid for derivative contracts in our synthetic fuels businesses. These impacts were partially offset by a $157 million decrease in inventory purchases in 2007, primarily related to coal purchases at the Utilities; $106 million of working capital changes related to the divestiture of CCO; and $47 million in net refunds of cash collateral previously paid to counterparties on derivative contracts in the current year compared to $47 million in net cash payments in the prior year at PEF. The decrease in recovery of fuel costs is due to a $335 million decrease at PEF driven by the 2006 recovery of previously under-recovered fuel costs, partially offset by a $56 million increase in the recovery at PEC driven by the 2007 recovery of previously under-recovered fuel costs.

Cash from operating activities for 2006 increased when compared with 2005. The $534 million increase in operating cash flow was primarily due to a $713 million increase in the recovery of fuel costs at the Utilities, a $248 million increase from the change in accounts receivable, approximately $103 million of proceeds received from the restructuring of a long-term coal supply contract at our discontinued terminals operations, and $72 million related to recovery of storm restoration costs at PEF. These impacts were partially offset by $141 million related to a wholesale customer prepayment in 2005 at PEC, as discussed below, a $108 million decrease from the change in accounts payable and a $96 million net increase in tax payments in 2006 compared to 2005. The increase in recovery of fuel costs was largely driven by the recovery of previously under-recovered 2005 fuel costs. The $248 million change in accounts receivable included $147 million at PEC, principally driven by the timing of wholesale sales, and $47 million at PEF, primarily related to timing of receipts. The $108 million decrease from the change in accounts payable was primarily related to our discontinued and abandoned operations (See Note 3).

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 covered approximately two years of electricity service and included a prepayment discount of approximately $16 million.

In 2007 and 2006, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. In 2005, PEF 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" and Note 7C for additional information.

INVESTING ACTIVITIES

Net cash (used) provided by investing activities for the three years ended December 31, 2007, 2006 and 2005, was $(1.457) billion, $127 million and $(1.144) billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.199 billion and $1.546 billion in 2007 and 2006, respectively, or approximately 100 percent of consolidated capital expenditures for continuing operations in both 2007 and 2006. Capital expenditures at the Utilities are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $675 million in 2007 and $1.657 billion in 2006, cash used in investing activities increased by $602 million. The increase in 2007 was primarily due to a $539 million increase in gross property additions at the Utilities, primarily at PEF, and a $114 million increase in nuclear fuel additions, partially offset by a decrease in property additions at our diversified businesses, most of which have been discontinued or abandoned. At PEC, utility property additions primarily related to an increase in spending for compliance with the Clean Smokestacks Act. At PEF, the increase in utility property additions is primarily due to environmental compliance projects, repowering the Bartow plant to more efficient natural gas-burning technology, which will not be completed until 2009, and nuclear and transmission projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1.657 billion in 2006 and $475 million in 2005, cash used in investing activities decreased by $89 million in 2006 when compared with 2005. The decrease in 2006 was primarily due to a $319 million increase in net proceeds from available-for-sale securities and other investments, a $12 million decrease in nuclear fuel additions, and a $17 million decrease in other investing activities, largely offset by a $333 million increase in capital expenditures for utility property. At PEC, the increase in utility property was primarily due to environmental compliance and mobile meter reading project expenditures. At PEF, the increase in utility property was primarily due to repowering the Bartow plant to more efficient natural gas-burning technology, which will not be completed until 2009; various distribution, transmission and steam production projects; and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. The increase in utility property additions was partially offset by an $84 million decrease related to diversified businesses, which have primarily been discontinued or abandoned. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

During 2007, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $615 million from the sale of PVI's CCO generation assets (See Note 3A), working capital adjustments for Gas, and the sale of poles at Progress Telecommunications Corporation.

During 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $1.1 billion from the sale of Gas (See Note 3C), $405 million from the sale of DeSoto and Rowan (See Note 3D), approximately $70 million from the sale of PT LLC (See Note 3E), approximately $27 million from the sale of certain net assets of the coal mining business (See Note 3G), and approximately $16 million from the sale of Dixie Fuels (See Note 3F).

During 2005, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included $405 million in proceeds from the sale of Progress Rail in March 2005 (See Note 3H) and $42 million in proceeds from the sale of Winter Park distribution assets in June 2005 (See Notes 3K and 7C).

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2007, 2006 and 2005, was $195 million, $(2.468) billion and $227 million, respectively. See Note 12 for details of debt and credit facilities.

The increase in net cash provided by financing activities for 2007 compared to 2006 primarily related to the issuance of $750 million in long-term debt at PEF and the $1.7 billion reduction in holding company debt in 2006, as discussed below.

For 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, were used to reduce holding company debt by $1.7 billion. The increase in cash used in financing activities for 2006 compared to 2005 was primarily related to the retirement of long-term debt in 2006, as discussed below, and a decrease in the proceeds from issuances of long-term debt.

2007

- On July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings.

- On August 15, 2007, due to extreme volatility in the commercial paper market, Progress Energy borrowed $400 million under its $1.13 billion revolving credit agreement (RCA) to repay outstanding commercial paper. On October 17, 2007, Progress Energy used $200 million of commercial paper proceeds to repay a portion of the amount borrowed under the RCA. On December 17, 2007, Progress Energy used $200 million of available cash on hand to repay the remaining amount borrowed under the RCA.

- On August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On

September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.

- On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

- On December 10, 2007, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $35 million of its 6.75% Medium-Term Notes with available cash on hand.

- On December 13, 2007, PEF filed a shelf registration statement with the SEC, which became effective with the SEC on January 8, 2008. The registration statement will allow PEF to issue up to $4 billion in first mortgage bonds, debt securities and preferred stock in addition to $250 million of previously registered but unsold securities.

- Progress Energy issued approximately 3.4 million shares of common stock resulting in approximately $151 million in proceeds from its Investor Plus Stock Purchase Plan and its stock option plan. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million to meet the requirement of the Investor Plus Stock Purchase Plan. For 2007, the dividends paid on common stock were approximately $627 million.

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. The net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds were used to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006, effectively terminating our $800 million 364-day credit agreement as discussed below.

- On March 31, 2006, Progress Energy, as a well-known seasoned issuer, filed a shelf registration statement with the SEC, which became effective upon filing with the SEC. Progress Energy's board of directors has authorized the issuance and sale by the Parent of up to $1.679 billion aggregate principal amount of various securities (See "Credit Facilities and Registration Statements").

- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006 (See "Credit Facilities and Registration Statements").

- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").

- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").

- On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.

- On November 1, 2006, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $60 million of its 7.17% Medium-Term Notes with available cash on hand.

- On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.

- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.

- Progress Energy issued approximately 4.2 million shares of common stock resulting in approximately $185 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 million.

2005

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was subsequently terminated on May 16, 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. 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, the $800 million of 6.75% Senior Notes was retired, thus effectively terminating the 364-day credit agreement.

- PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015; $200 million of First Mortgage Bonds, 5.70% Series due 2035; and $400 million of First Mortgage Bonds, 5.25% Series due 2015. PEC paid at maturity $300 million in 7.50% Senior Notes. PEC also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on June 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.

- PEF issued $300 million in Mortgage Bonds, 4.50% Series due 2010 and $450 million in Series A Floating Rate Senior Notes due 2008. PEF paid at maturity $45 million in 6.72% Medium-Term Notes, Series B. PEF also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on March 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.

- 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. Included in these amounts were approximately 4.6 million shares for proceeds of approximately $199 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2005, the dividends paid on common stock were approximately $582 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" for a discussion of the factors that may impact any such forward-looking statements made herein.

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2007, 2006 and 2005. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels businesses, whose operations have been reclassified to discontinued operations, have historically produced significant earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). These tax credits have yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. As of December 31, 2007, we have carried forward $830 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

With the exception of the anticipated proceeds in 2008 from the sale of our coal mining and terminals operations (See Notes 3B and 3G), the absence of cash flow resulting from divested businesses is not expected to impact our future liquidity or capital resources as these businesses in the aggregate have been largely cash flow neutral over the last several years.

Cash from operations plus availability under our credit facilities and shelf registration statements is expected to be sufficient to meet our requirements in the near term. To the extent necessary, we may also use limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. In the latter half of 2007, the short-term credit markets tightened, resulting in higher interest rate spreads and shorter durations. Currently, the market has improved; however, there has been volatility on commercial paper spreads, as the supply of short-term commercial paper has increased following recent actions by the Federal Open Market Committee. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing from our RCAs, issuing short-term floating rate notes, and/or issuing long-term debt.

Progress Energy has approximately $9.7 billion in outstanding debt. Only $860 million of our debt is insured. These bonds are obligations of the Utilities and are traded in the tax-exempt auction rate securities market. Ambac Assurance Corporation insures approximately $620 million of the bonds and XL Capital Assurance, Inc. insures the remaining $240 million. To date, auctions for the Utilities' bonds have seen an increase in the interest rates that are periodically reset at each auction. Since the downgrade of XL Capital Assurance, Inc. on February 7, 2008, by Moody's Investors Service, Inc. (Moody's), we have seen additional market volatility and an increase in the reset interest rates for a portion of our tax-exempt bonds. If additional downgrades by Moody's or Standard & Poor's Rating Services (S&P) occur, we could see additional volatility in this market and the potential for higher rate resets. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

Over the long term, meeting the anticipated load growth at the Utilities will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in both Florida and the Carolinas toward the end of the next decade. This approach will require the Utilities to make significant capital investments. See "Introduction – Strategy" for additional information. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

The amount and timing of future sales of 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 immediately 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 corporate purposes.

At December 31, 2007, the current portion of our long-term debt was $877 million, which we expect to fund with a combination of cash from operations, proceeds from sales of assets, commercial paper borrowings and long-term debt. See Note 3 for additional information on asset sales.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, as discussed in "Other Matters – Regulatory Environment" and Note 7, and filings for recovery of environmental costs, as discussed in Note 21 and in "Other Matters – Environmental Matters," may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources.

PEC Base Rates

PEC's base rates are subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

PEC Pass-through Clause Cost Recovery

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kWh, or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006;

$48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

As discussed further in "Other Matters – Regulatory Environment," South Carolina and North Carolina state energy legislation that became law in 2007 may impact our liquidity over the long term. Among other provisions, these state energy laws provide mechanisms for recovery of certain baseload generation construction costs and expand annual fuel clause mechanisms so that additional costs may be recovered annually.

Comprehensive energy legislation enacted in 2007 in North Carolina expanded the costs that may be recovered annually under the fuel clause, including costs of reagents used in emissions control technologies (commodities such as ammonia and limestone), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause. Energy legislation enacted in 2007 in South Carolina expanded the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of emissions control technologies. We anticipate PEC's reagent and purchased power costs eligible for jurisdictional recovery under the North Carolina and South Carolina energy laws will total approximately $50 million in 2008.

The North Carolina law mandates minimum Renewable Energy and Energy Efficiency Portfolio Standards (REPS) beginning in 2012. Utilities are allowed to recover the premium to be paid to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligation under the REPS, regardless of the actual renewables generated or purchased. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

In addition, the North Carolina law also allows PEC to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods. PEC has begun implementing a series of DSM and energy-efficiency programs and for the year ended December 31, 2007, deferred $2 million of implementation and program costs for future recovery.

See "Other Matters – Regulatory Environment" for additional information about state and federal legislation.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with 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 the agreement through the last billing cycle of June 2010. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between a specified threshold and specified cap, which will be adjusted annually, and 100 percent of revenues above the specified cap. PEF's retail base revenues did not exceed the specified 2007 or 2006 thresholds, and thus no revenues were subject to revenue sharing. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the 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. If PEF's regulatory return on equity (ROE) falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

On October 23, 2007, the FPSC approved a stipulation and settlement agreement that settled all issues related to recovery of the revenue requirements of Hines Unit 2 and Hines Unit 4 and provided that PEF shall 1) increase its base rates for the revenue requirements of Hines Unit 2 and Hines Unit 4 and 2) simplify the implementation of the base rate increase of $89 million by making it effective with the first billing cycle in January 2008. The revenue requirements of Hines Unit 2 were previously being recovered through the fuel clause.

PEF Pass-through Clause Cost Recovery

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008, and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased effective January 1, 2008, by $2.73 for the first 1,000 kWh. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF was over-recovered in fuel and capacity costs by $140 million, over-recovered in conservation costs by $14 million, over-recovered in environmental compliance by $5 million and had accrued disallowed fuel costs of $14 million as discussed below.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices were prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate Crystal River Unit No. 3 Nuclear Plant (CR3), bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. On February 8, 2007, the FPSC issued an order approving PEF's request for a need determination to uprate through a multi-stage uprate to be completed by 2012. PEF's need determination filing included estimated project costs of approximately $382 million. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing on the matter to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, instrumentation modifications for improved accuracy, estimated at $6 million through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the ECRC, which were estimated to be $31 million at December 31, 2007. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR through the ECRC (see "Other Matters – Environmental Matters" for discussion regarding CAMR). The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $1.3 billion to $2.3 billion.

Storm Cost Recovery

On August 29, 2006, the FPSC approved a settlement agreement related to PEF's storm cost-recovery docket that allowed PEF to extend its then-current two-year storm surcharge. The requested 12-month extension, which began in August 2007, will replenish the existing storm reserve by an estimated $126 million. In the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. Intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

Nuclear Cost Recovery

The FPSC approved new rules on February 13, 2007, that allow PEF to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility.

Other Regulatory Matters

Additionally, on July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry, and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry, and emissions reduction targets that are similar to those contained in the governor's executive orders. We cannot currently predict the impacts to our liquidity of complying with these executive orders and the Florida Energy Commission's recommendations.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. On June 18, 2007, compliance with 83 FERC-approved reliability standards became mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. On December 20, 2007, the FERC approved three additional planning and operating reliability standards. Additionally, on January 17, 2008, the FERC approved eight mandatory critical infrastructure protection reliability standards to protect the bulk power system against potential disruptions from cyber security breaches.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our cash flows.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2007.

As shown in the table below, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. We anticipate our regulated capital expenditures will increase in 2008 and 2009, primarily due to increased spending on environmental initiatives and current growth and maintenance projects. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2007**	2008	2009	2010
Regulated capital expenditures	**$ 1,874**	$ 2,420	$ 2,080	$ 1,670
Nuclear fuel expenditures	**228**	260	290	270
AFUDC – borrowed funds	**(16)**	(40)	(50)	(40)
Other capital expenditures	**10**	20	20	20
Total before potential nuclear construction	**2,096**	2,660	2,340	1,920
Potential nuclear construction[(a)]	**94**	160	520	850
Total	**$ 2,190**	$ 2,820	$ 2,860	$ 2,770

(a) Expenditures for potential nuclear construction are net of AFUDC – borrowed funds and include land, development, licensing, equipment and associated transmission. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build; final contract negotiations; timing and escalation of project costs; and the percentages, if any, of joint ownership. These expenditures, which are primarily at PEF, are subject to cost-recovery provisions in the Utilities' respective jurisdictions (see discussion under "Other Matters – Nuclear").

Regulated capital expenditures for 2008, 2009 and 2010 in the table above include approximately $730 million, $350 million and $130 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2008, 2009 and 2010 include $180 million, $70 million and $80 million, respectively, at PEC and $550 million, $280 million and $50 million, respectively, at PEF. We currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $700 million at PEC and in excess of $1.9 billion at PEF through 2018, which is the latest compliance target date for current air and water quality regulations. See "Other Matters – Environmental Matters" 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.

CREDIT FACILITIES AND REGISTRATION STATEMENTS

The following table summarizes our RCAs and available capacity at December 31, 2007:

(in millions)	Description	Total	Outstanding	Reserved[(a)]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$ 1,130	$ –	$ 220	$ 910
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$ 2,030	$ –	$ 220	$ 1,810

[(a)] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

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. See Note 12 for additional discussion of our credit facilities.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings. Fees and interest rates under Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's and BBB by S&P. Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P. Fees and interest rates under PEF's RCA are 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.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2007. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2007, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 12.

Progress Energy, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which Progress Energy may issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2007, Progress Energy has the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

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

PEF has on file with the SEC a shelf registration statement under which it can issue up to $4.250 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, 2007, PEC and PEF could issue up to $3.657 billion and $2.408 billion, respectively, based on property additions and $1.827 billion and $175 million, respectively, based upon retirements of previously issued first mortgage bonds.

CAPITALIZATION RATIOS

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

	2007	2006
Common stock equity	**45.7%**	47.2%
Preferred stock and minority interest	**1.0%**	0.6%
Total debt	**53.3%**	52.2%

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	Stable	Stable	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F-2
PEC			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	A-
PEF			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB	A
Preferred stock	Baa2	BBB-	A-
FPC Capital I			
Quarterly Income Preferred Securities (a)	Baa2	BBB-	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt (b)	Baa1	BBB	n/a

(a) Guaranteed by Progress Energy, Inc. and Florida Progress.
(b) Guaranteed by 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 September 6, 2007, S&P upgraded the first mortgage bonds of both PEC and PEF to A- from BBB+ as a result of a methodology change for collateral coverage requirements. Because both PEC and PEF had asset to potential secured debt ratios of less than 1.5, they were assigned a recovery rating of 1, which qualified for a one-notch increase over their corporate credit ratings.

On July 13, 2007, Fitch Ratings upgraded the long-term ratings of both PEC and PEF to A- from BBB+ and revised their rating outlooks to stable from positive. Fitch Ratings cited cash flow coverage and leverage credit ratios more consistent with the A rating category at the Utilities, sound utility operations and operations in historically favorable regulatory environments as the primary factors for the upgrades. Fitch Ratings also noted lowered group linkage risks for PEC and PEF resulting from improved business risk at the Parent due to the sale or wind-down of non-utility operations and reduced debt.

On June 15, 2007, Moody's upgraded the corporate credit rating for PEC to A3 from Baa1 and revised its outlook to stable from positive. Moody's cited strong cash flow coverage measures and financial metrics, operations in constructive regulatory environments with growing service territories and lower debt and business risk at the Parent as the primary factors in the upgrade.

On March 15, 2007, S&P upgraded corporate credit ratings to BBB+ from BBB at Progress Energy, Inc., PEC and PEF and revised each company's outlook to stable from positive. S&P cited the significant reduction in our holding company debt and the moderation of business risk achieved by our renewed focus on our regulated utilities as the primary factors in the upgrade.

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." 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 standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2007, we have issued $481 million of guarantees for future financial or performance assurance, including $17 million at PEC and $1 million at PEF. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At December 31, 2007, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

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 17 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 to the Consolidated Financial Statements. 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, 2007, 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)	$9,668	$877	$806	$1,950	$6,035
Interest payments on long-term debt (b)	6,865	558	1,003	816	4,488
Capital lease obligations (See Note 22B)	657	28	57	63	509
Operating leases (See Note 22B)	740	62	66	58	554
Fuel and purchased power (c) (See Note 22A)	17,644	2,473	3,778	2,534	8,859
Other purchase obligations (d) (See Note 22A)	1,228	808	324	32	64
Minimum pension funding requirements (e)	193	34	105	54	–
Uncertain tax positions(f) (See Note 14)	–	–	–	–	–
Other commitments (g)	133	13	27	27	66
Total	$37,128	$4,853	$6,166	$5,534	$20,575

(a) Our maturing debt obligations are generally expected to be repaid with asset sales and cash from operations or refinanced with new debt issuances in the capital markets.

(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2007.

(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) We have additional contractual obligations associated with our discontinued CCO operations, which are not reflected in this table. These obligations include other purchase obligations of $3 million each for 2008 and 2009.

(e) Projected pension funding status is based on current actuarial estimates and is subject to future revision.

(f) Uncertain tax positions of $93 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.

(g) In 2008, PEC must begin transitioning North Carolina jurisdictional 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.

OTHER MATTERS

SYNTHETIC FUELS TAX CREDITS

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualified for federal income tax credits so long as certain requirements were 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 fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year were phased out if annual average market prices for crude oil exceeded certain prices. Synthetic fuels were generally not economical to produce and sell absent the credits. The synthetic fuels tax credit program expired at the end of 2007.

TAX CREDITS

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K) effective January 1, 2006. 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 carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general

business credit removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision allowed us to produce more synthetic fuels than we have historically produced, should we have chosen to do so.

Total Section 29/45K credits generated through December 31, 2007 (including those generated by Florida Progress prior to our acquisition), were approximately $2.028 billion, of which $1.054 billion has been used to offset regular federal income tax liability, $830 million is being carried forward as deferred tax credits and $144 million has been reserved due to the estimated phase-out of tax credits due to high oil prices, as described below.

IMPACT OF CRUDE OIL PRICES

Section 29 provided that if the Annual Average Price exceeded the Threshold Price, the amount of Section 29/45K tax credits was reduced for that year. Also, if the Annual Average Price exceeded the Phase-out Price, the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation.

If the Annual Average Price fell between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits were reduced depended on where the Annual Average Price fell in that continuum. The Department 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 2006 was published on April 4, 2007. Based on the Annual Average Price for calendar year 2006 of $59.68, our synthetic fuels tax credits generated during 2006 were reduced by 33 percent, or approximately $35 million. The Annual Average Price for calendar year 2007 is expected to be published in early April 2008.

On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities. As discussed below, the decision to idle production was based on the high level of oil prices, and the resumption of synthetic fuels production was dependent upon a number of factors, including a reduction in oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. The operation of synthetic fuels facilities on behalf of third parties continued through late 2007. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased in late December 2007, we reclassified the operations of our synthetic fuels businesses as discontinued operations in the fourth quarter of 2007.

We estimate that the 2007 Threshold Price will be approximately $57 per barrel and the Phase-out Price will be approximately $71 per barrel, based on an estimated inflation adjustment for 2007. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding daily New York Mercantile Exchange (NYMEX) prompt month settlement price for light sweet crude oil. Through December 31, 2007, the average NYMEX settlement price for light sweet crude oil was $72.35 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price and 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, 2007, we estimate that the synthetic fuels tax credit amount for 2007 will be reduced by approximately 70 percent. Therefore, we reserved 70 percent or approximately $144 million of the $205 million of tax credits generated during 2007. The final calculations of any reductions in the value of the tax credits will not be determined until April 2008 when final 2007 oil prices are published.

In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a NYMEX basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production and was marked-to-market with changes in fair value recorded through earnings. The derivative contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact on 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed below in “Sales of Partnership Interests” and in Notes 1C and 3J, we disposed of our 100 percent ownership interest in

Ceredo in March 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts, including $57 million attributable to Ceredo, of which $42 million was attributed to minority interest for the portion of the gain subsequent to disposal. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," and Note 17A and for a discussion of market risk and derivatives.

IMPAIRMENT OF SYNTHETIC FUELS AND OTHER RELATED LONG-LIVED ASSETS

We monitor our long-lived assets for impairment as warranted. With the idling of our synthetic fuels facilities during the second quarter of 2006 due to the high level of oil prices, we performed an impairment evaluation of our synthetic fuels and other related operating long-lived assets. The impairment test considered numerous factors, including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities. Based on the results of the impairment test, we recorded pre-tax impairment charges of $91 million ($55 million after-tax) during the quarter ended June 30, 2006 (See Notes 8 and 9). These charges represent the entirety of the asset carrying value of our synthetic fuels intangible assets and manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. As discussed in Note 3B, these charges have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

SALES OF PARTNERSHIP INTERESTS

In March 2007, we disposed of, through our subsidiary Progress Fuels, our 100 percent ownership interest in Ceredo, a subsidiary that produces and sells qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a nonrecourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying coal-based solid synthetic fuels on behalf of the buyer. During 2007, we produced 2.7 million tons. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million in 2007 and $5 million subsequent to year-end. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R), but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there was no net earnings impact from Ceredo's operations. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer, which increases the loss on disposal or reduces any potential deferred gain. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods (See Note 3J and Note 22C).

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of our synthetic fuels facilities. The transactions were structured such that proceeds from the sales would be received over time, which was typical of such sales in the industry. Gains from the sales are recognized on a cost-recovery basis. Gain recognition is dependent on the synthetic fuels production qualifying for Section 29/45K 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 were deferred. Due to the impact on production from the 2007 idling of the synthetic fuels facilities as discussed above and pursuant to the terms of the sales agreements, in January 2008, the purchasers abandoned their interests in Colona. We recognized a $4 million gain and $30 million gain on these transactions in the years ended December 31, 2006 and 2005, respectively, which have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3L). In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gain.

See Note 22D and Item 1A, “Risk Factors” for additional discussion related to our synthetic fuels operations.

REGULATORY ENVIRONMENT

The Utilities’ operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and other federal and state agencies common to the utility business. 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 one or more of these governmental agencies.

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail ratepayers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate when, or if, any of these states will move to increase retail competition in the electric industry.

The retail rate matters affected by state 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 on our consolidated financial statements.

On December 19, 2007, the president signed into law the federal Energy Independence and Security Act of 2007. The legislation strengthened Corporate Average Fuel Economy standards for automotive manufacturers’ fleets of passenger cars and light trucks and significantly increased the amount of ethanol required to be used as a gasoline additive. The legislation also provided incentives for the development of plug-in hybrid electric vehicles and created new energy-efficiency standards in commercial, residential and governmental use. In addition, the legislation authorized increased funding for research into the use of carbon capture and storage technology, and directs states to consider "smart grid" improvements to transmission infrastructure. The law did not contain any provisions for a federal Renewable Portfolio Standard.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law mandates minimum REPS for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state’s electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. The premium to be paid by electric utilities to comply with the requirements, above the cost they would have otherwise incurred to meet consumer demand, is to be recovered through an annual clause. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations under the REPS, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the REPS requirements if the NCUC determines it is in the public interest to do so. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

The law allows the utility to meet a portion of the REPS with energy reductions achieved through energy-efficiency programs. Energy-efficiency programs include any program or activity implemented after January 1, 2007, that results in less energy being used to perform the same function. Through the year 2020, a utility can use energy- efficiency programs to satisfy up to 25 percent of their REPS; beginning in 2021, these programs may constitute up to 40 percent of the requirements.

The law allows the utility to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. The law allows the utility to capitalize those costs that are intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs for future recovery for the year ended December 31, 2007.

The law also expands the definition of the traditional fuel clause so that additional costs may be recovered annually. These additional costs include costs of reagents (commodities such as ammonia and limestone used in emissions control technologies), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause (see additional discussion below). The North Carolina law also authorizes the NCUC to allow annual prudence reviews of the construction costs of a baseload generating plant if requested by the public utility that is constructing the plant and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction.

On October 26, 2007, the NCUC issued its proposed rules for implementation of the law. PEC expects final rules to be issued by the end of the first quarter of 2008. Until the rulemaking process is completed, we cannot predict the costs of complying with the law. PEC would be able to annually recover its reasonable prudent compliance costs.

During 2007, the South Carolina legislature ratified new energy legislation, which became law on May 3, 2007. Key elements of the law include expansion of the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of PEC's emissions control technologies (see additional discussion below). The law also includes provisions to provide base rate cost recovery for upfront development costs associated with nuclear baseload generation and construction costs associated with nuclear or coal baseload generation without a base rate proceeding and the ability to recover financing costs for new nuclear baseload generation through annual clauses.

On November 30, 2007, PEC filed a petition with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency program expenses pending the filing of application requesting a DSM and energy- efficiency program expense clause to recover such program costs. On December 12, 2007, the SCPSC granted PEC's petition. As a result, through December 31, 2007, PEC deferred an immaterial amount of implementation and program costs for future recovery in the South Carolina jurisdiction.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions.

Among other things, the executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers, who generate electricity from on-site renewable technologies of up to 1 MW in capacity, to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry and emissions reduction targets that are similar to those contained in the governor's executive orders. We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders and the Florida Energy Commission's recommendations. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

On April 10, 2007, the FPSC adopted a rule that specifies what storm costs will be recoverable and whether such recoverable costs would be offset against a utility's storm reserve fund or recoverable through its base rates. PEF does not believe that compliance with this rule will materially increase its costs.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. EPACT provides procedures and rules for the establishment of an electric reliability organization (ERO) that will propose and enforce mandatory reliability standards. On July 20, 2006, the FERC certified the North American Electric Reliability Corporation (NERC) as the ERO. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards in particular regions of the country by entering into delegation agreements with regional entities. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

As discussed in "Future Liquidity and Capital Resources – Other Regulatory Matters," during 2007 and 2008, the FERC approved a significant number of reliability standards developed by the NERC and set aside other standards pending further development. Compliance with FERC-approved reliability standards is mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. Prior to the FERC action, electric utility industry compliance with the NERC standards had been voluntary.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Prior to the effective date of mandatory compliance with the reliability standards, PEC self-reported two noncompliances and PEF self-reported three noncompliances. Entities responsible for enforcement of mandatory reliability standards have proposed that entities that self-reported noncompliance prior to the effective date and pursue aggressive mitigation plans will not be assessed fines. Subsequent to the effective date, PEC self-reported three noncompliances with voluntary standards and PEF self-reported one noncompliance with voluntary standards and one noncompliance with a mandatory standard. PEC and PEF have submitted mitigation plans to address the self-reported noncompliance. The costs of executing the mitigation plans are not expected to have a significant effect on our results of operations or liquidity.

LEGAL

We are subject to federal, state and local legislation and court orders. These matters are discussed in detail in Note 22D. This discussion identifies specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

INCREASING ENERGY DEMAND

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

We are actively pursuing expansion of our energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. Our energy-efficiency program provides simple, low-cost ways for residential customers to reduce energy use, promotes home energy checks, provides tools and programs for large and small businesses to minimize their energy use and provides an interactive internet Web site with online calculators, programs and efficiency tips.

We are actively engaged in a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants. While we pursue expansion of energy- efficiency and conservation programs, PEC has announced a two-year moratorium on constructing new coal-fired plants and that if PEC goes ahead with a new nuclear plant, the new plant would not be online until at least 2018 (see "Nuclear" below).

As authorized under EPACT, on October 4, 2007, the United States Department of Energy (DOE) published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects. Congress has approved $4 billion in loan guarantees, with the DOE seeking an additional $9 billion in loan guarantees in its fiscal 2008 budget request. Initial applications for loan guarantees were for non-nuclear projects but it is expected that approval of additional funding could result in guarantees being available for nuclear generation projects. We cannot predict the outcome of this matter.

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 take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved.

On November 14, 2006, PEC filed an application with the NRC for a 20-year extension of the Shearon Harris Nuclear Plant (Harris) operating license. The license renewal application for Harris is currently under review by the NRC with a decision expected in 2008.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 5 and 22D).

We previously announced that we are pursuing development of COL applications to potentially construct new nuclear plants in North Carolina and Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, the new plant would not be online until at least 2018 (See "Increasing Energy Demand" above).

On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. PEF expects to file the application for the COL in 2008. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, safety-related construction activities could begin as early as 2012, and a new plant could be online in 2016 (See "Increasing Energy Demand" above). In 2007, PEF completed the purchase of approximately 5,000 acres for the Levy County site and associated transmission needs. PEF anticipates filing a Determination of Need petition with the FPSC in 2008. In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF's requests to change the comprehensive land use plan. The Florida Department of Community Affairs

(FDCA) reviewed the proposed changes to the comprehensive land use plan and in their report, the FDCA expressed concerns related to the intensity of use and environmental suitability for some of the proposed amendments impacting PEF's proposed Levy County nuclear site. We anticipate that the Levy County Planning Commission will resolve the FDCA's concerns without impact to the potential project schedule. We cannot predict the outcome of this matter.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per 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 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the IRS provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

In accordance with provisions of Florida's comprehensive energy bill enacted in 2006, the FPSC ordered new rules in December 2006 that would allow investor-owned utilities such as PEF to request recovery of certain planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

In 2007, the South Carolina legislature ratified new energy legislation, which includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. The North Carolina legislature ratified new energy legislation, which authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. 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 frequently change and the ultimate costs of compliance cannot be precisely estimated.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North 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, the state of Florida or potentially responsible parties (PRP) groups. 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 PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. Hazardous and solid waste management matters are discussed in detail in Note 21A.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated in accordance with GAAP. 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 could change and additional losses, which could be material, may be incurred in the future.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which would likely result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxides (NOx), SO_2, 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 pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAVR and mercury regulation, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described below. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. PEC has completed installation of controls to meet the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) requirements. The NOx SIP Call is not applicable to Florida. Expenditures for the NOx SIP Call include the cost to install NOx controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. The air quality controls installed to comply with the NOx SIP Call and Clean Smokestacks Act will result in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. The timing and extent of the costs for future projects will depend upon final compliance strategies.

Progress Energy

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2007
Clean Smokestacks Act	2002–2013	$1,100 – 1,400	$892
CAIR/CAVR/mercury regulation	2005–2018	1,500 – 2,600	333
Total air quality		2,600 – 4,000	1,225
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$2,600 – 4,000	$1,225

PEC

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2007
Clean Smokestacks Act	2002–2013	$1,100 – 1,400	$892
CAIR/CAVR/mercury regulation	2005–2018	200 – 300	10
Total air quality		1,300 – 1,700	902
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$1,300 – 1,700	$902

PEF

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2007
CAIR/CAVR/mercury regulation	2005–2018	$1,300 – 2,300	$323
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$1,300 – 2,300	$323

(a) Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."

To date, under the first phase of Clean Smokestacks Act emission reductions, all environmental compliance projects at our Asheville plant and several projects at our Roxboro plant have been placed in service. The remaining projects at our two largest plants, Roxboro and Mayo, are under construction and are expected to be completed in 2008 and 2009, respectively. The remaining projects to comply with the second phase of emission reductions, which are smaller in scope, have not yet begun. These estimates are currently under review and are conceptual in nature and subject to change.

To date, expenditures at PEF for CAIR/CAVR/mercury regulation primarily relate to environmental compliance projects under construction at CR5 and CR4, which are expected to be placed in service in 2009 and 2010, respectively. See discussion of projects for Crystal River Units No. 1 and No. 2 to meet CAVR beyond-BART requirements below.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (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 has undertaken civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities, several of which were 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 April 2, 2007, the U.S. Supreme Court issued a ruling on an appeal of a decision of the U.S. Court of Appeals for the Fourth Circuit, in a case involving an unaffiliated utility. The Fourth Circuit held that NSR applies to projects that result in an increase in maximum hourly emissions. The U.S. Supreme Court rejected the lower court decision and held that the EPA is not required to adopt the maximum hourly emissions test but may use an actual annual emissions test to determine whether NSR applies.

On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) set aside the EPA's 2003 NSR equipment replacement rule. The rule would have provided a more uniform definition of routine equipment replacement, which is excluded from NSR applicability. The D.C. Court of Appeals denied a request by the EPA for a re-hearing regarding this matter on June 30, 2006. On November 27, 2006, the EPA filed a petition for a writ of certiorari requesting that the U.S. Supreme Court review the decision of the D.C. Court of Appeals. On April 30, 2007, the U.S. Supreme Court denied the EPA's petition. In a previous case decided in late 2005, the D.C. Court of Appeals had also set aside a provision in the NSR rule that had exempted the installation of pollution control projects from review. These projects are now subject to NSR requirements, adding time and cost to the installation process.

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 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In March 2007, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.1 billion to $1.4 billion at the time of the filing. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million 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 continuing to evaluate various design, technology and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the equipment. Recent legislation in North Carolina and South Carolina expanded the traditional fuel clause to include the annual recovery of reagents and certain other costs; all other O&M expenses are currently recoverable through base rates. On March 23, 2007, PEC filed a petition with the NCUC regarding future recovery of costs to comply with the Clean Smokestacks Act, and on October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, CUCA and CIGFUR supporting PEC’s proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis. See further discussion about the Clean Smokestacks Act in Note 7B. We cannot predict the outcome of this matter.

Two of PEC’s largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. In 2005, PEC entered into an agreement with the joint owner to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B).

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 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. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule

On March 10, 2005, the EPA issued the final CAIR. The EPA’s rule requires the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, 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. States were required to adopt rules implementing the CAIR. The EPA approved the North Carolina CAIR on October 5, 2007, the South Carolina CAIR on October 9, 2007, and the Florida CAIR on October 12, 2007.

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 D.C. Court of Appeals 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. On March 16, 2006, the EPA denied all pending reconsiderations, allowing the challenge to proceed. 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. Oral argument has been set by the D.C. Court of Appeals for March 25, 2008. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAIR, which is very similar to the EPA’s model rule. An unaffiliated utility challenged the state-adopted rule. On November 7, 2007, the Florida District Court of Appeals ruled against the challenge and in favor of the Florida Department of Environmental Protection. The outcome of these matters cannot be predicted. On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that sets mercury 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 delisting rule that eliminated any requirement to pursue a maximum achievable control technology 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 delisting rule was challenged by a number of parties. Sixteen states subsequently petitioned for a review of the EPA’s determination confirming the delisting. On February 8, 2008, the D.C. Court of Appeals decided in favor of the petitioners and vacated the delisting determination and the CAMR. The exact impacts of this decision are uncertain until the court’s mandate is issued. The three states in which the Utilities operate have adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the vacation of the federal CAMR will affect the state rules.

On June 15, 2005, the EPA issued the final 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, including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. The reductions associated with BART begin in 2013. 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. Plans for compliance with CAIR and mercury regulation may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. On December 4, 2007, the Florida Department of Environmental Protection finalized a Regional Haze implementation rule that requires sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. PEC’s BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF’s BART-eligible units are Anclote Units No. 1 and No. 2, Bartow Unit No. 3 and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted. On December 12, 2006, the D.C. Court of Appeals decided in favor of the EPA in a case brought by the National Parks Conservation Association that alleges the EPA acted improperly by substituting the requirements of CAIR for BART for NOx and SO_2 from electric generating units in areas covered by CAIR.

PEC and PEF are each developing an integrated compliance strategy to meet all the requirements of the CAIR, CAVR and mercury regulation. We are evaluating various design, technology and new generation options that could change PEC’s and PEF’s costs to meet the requirements of CAIR, CAVR and mercury regulation.

The integrated compliance strategy PEF anticipates implementing should provide most, but not all, of the NOx reductions required by CAIR. Therefore, PEF anticipates utilizing the cap-and-trade feature of CAIR by purchasing annual and seasonal NOx allowances. Because the emission controls cannot be installed in time to meet CAIR’s NOx requirements in 2009, PEF anticipates purchasing a higher level of annual and seasonal allowances in that year. The costs of these allowances would depend on market prices at the time these allowances are purchased. PEF expects to recover the costs of these allowances through its ECRC.

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, CAMR and CAVR through the ECRC (see discussion above regarding CAMR). On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF’s recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF’s petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy. On June 1, 2007, PEF filed a supplemental petition for approval of its compliance plan and associated contracts and recovery of costs for air pollution control projects, which included approximately $1.0 billion to $2.3 billion of estimated capital costs for the range of alternative plans. The estimated capital cost for the recommended plan, which was $1.26 billion in the June 1, 2007 filing, represents the low end of the range in the table of estimated required environmental expenditures shown above. The difference in costs between the recommended plan and the high end of the range represents the additional costs that may be incurred if pollution controls are required on Crystal River Units No. 1 and No. 2 in order to comply with the requirements of CAVR beyond BART, should reasonable progress in improving visibility not be achieved, as discussed above. The increase from the estimates filed in March 2006 is primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. 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 March 16, 2006, the EPA issued a final 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. On June 26, 2006, the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's final action on the petition. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On December 21, 2005, the EPA announced proposed changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter (PM 2.5) 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 (PM 2.5-10). The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter (PM 10). On September 20, 2006, the EPA announced that it is finalizing the PM 2.5 NAAQS as proposed. In addition, the EPA decided not to establish a PM 2.5-10 NAAQS, and it is eliminating the annual PM 10 NAAQS, but the EPA is retaining the 24-hour PM 10 NAAQS. These changes are not expected to result in designation of any additional nonattainment areas in PEC's or PEF's service territories. On December 18, 2006, environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter. The outcome of this matter cannot be predicted.

On June 20, 2007, the EPA announced proposed changes to the NAAQS for ground-level ozone. The EPA proposed to lower the 8-hour primary standard from 0.08 parts per million to a range of 0.070 to 0.075 parts per million. The two alternatives proposed for the secondary standard are to either establish a new cumulative, seasonal standard or set the secondary standard as identical to the proposed primary standard. Depending on air quality improvements expected over the next several years as current federal requirements are implemented, additional nonattainment areas may be designated in PEC's and PEF's service territories. The final rule is expected in March 2008. The outcome of this matter cannot be predicted.

Water Quality

1. General

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.

2. Section 316(b) of the Clean Water Act

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004. The July 2004 rule required assessment of the baseline environmental effect of withdrawal of cooling water and development of technologies and measures for reducing environmental effects by certain percentages. Additionally, the rule authorized establishment of alternative performance standards where the site-specific costs of achieving the otherwise applicable standards would have been substantially greater than either the benefits achieved or the costs considered by the EPA during the rulemaking.

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA. On July 9, 2007, the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitting authorities establish best available technology controls for minimizing adverse environmental impact at existing cooling water intake structures on a case-by-case, best professional judgment basis. On November 2, 2007, the Utility Water Act Group and several unaffiliated utilities filed petitions for writ of certiorari to the U.S. Supreme Court. On December 31, 2007, 13 states filed an amicus brief in support of the Utility Water Act Group's petition. As a result of these recent developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

3. North Carolina Groundwater Standard

In 2006, the North Carolina Environmental Management Commission granted approval for North Carolina Division of Water Quality (NCDWQ) staff to publish a notice in the North Carolina Register and schedule public hearings regarding the NCDWQ’s recommendation to revise the state’s groundwater quality standard for arsenic to 0.00002 milligrams/liter from 0.05 milligrams/liter. To date, no further action has been taken by the NCDWQ staff on this matter.

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 favors voluntary programs. There are proposals and ongoing studies at the state and federal levels, including the state of Florida, to address global climate change that would regulate CO_2 and other greenhouse gases. See further discussion of the executive orders issued by the governor of Florida to address reduction of greenhouse gas emissions under “Other Matters – Regulatory Environment.”

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 ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. 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 action on this important issue as discussed under “Other Matters – Increasing Energy Demand.” In 2007, we issued a corporate responsibility summary report, which discusses our actions, and in 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. 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.

In a decision issued July 15, 2005, the D.C. Court of Appeals denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation. The U.S. Supreme Court agreed to hear the case and on April 2, 2007, it ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. The impact of this decision cannot be predicted.

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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" 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 August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.

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

See discussion of PEC's credit ratings in Progress Energy "Credit Rating Matters."

PEC expects to have sufficient resources to meet its future obligations through a combination of internally generated funds, commercial paper borrowings, money pool borrowings, its credit facilities, long-term debt, preferred stock and/or contribution of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

In 2007, cash provided by operating activities decreased when compared to 2006. The $76 million decrease was primarily due to an $89 million decrease from accounts payable and payables to affiliates, a $79 million decrease from the change in accounts receivable and receivables from affiliated companies, and a $27 million pension funding payment in 2007. These impacts were partially offset by $63 million in lower coal inventory purchases in 2007 and a $56 million increase in the recovery of fuel costs driven by the 2007 recovery of previously under-recovered fuel costs. The decrease from accounts payable and payables to affiliates was largely related to the timing of settlements with affiliates. The decrease from the change in accounts receivable was primarily due to higher collections in the prior year of wholesale billings and the impact of weather.

In 2006, cash provided by operating activities increased when compared to 2005. The $62 million increase in operating cash flow was primarily due to a $147 million increase from the change in accounts receivable, a $136 million increase in the recovery of fuel costs, and a $47 million increase from the change in accounts payable. In 2006 and 2005, PEC filed requests with the NCUC and SCPSC 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 7B. The change in accounts receivable was principally driven by the timing of wholesale sales. The change in accounts payable was largely driven by the timing of environmental compliance project payments and other vendor payments. These impacts were partially offset by $141 million related to a wholesale customer prepayment in 2005 and a $122 million net increase in tax payments in 2006 compared to 2005. In 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.

In 2007, cash used by investing activities increased approximately $170 million when compared with 2006. The increase was primarily due to a $91 million decrease in net proceeds from available-for-sale securities and other investments, an $82 million increase in nuclear fuel additions due to an additional outage in 2007 compared to 2006, and $52 million in additional capital expenditures for utility property. Utility property additions primarily related to an increase in spending for compliance with the Clean Smokestacks Act. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

In 2006, cash used by investing activities decreased approximately $89 million when compared with 2005. The decrease was due primarily to a $250 million increase in net proceeds from available-for-sale securities and other investments, largely offset by $102 million in additional capital expenditures for utility property, primarily related to an increase in spending for compliance with the Clean Smokestacks Act, and $23 million in nuclear fuel additions.

Net cash used by financing activities decreased $254 million for 2007 when compared to 2006, primarily due to a decrease in dividends paid to the Parent and an increase in advances from affiliated companies, partially offset by a $200 million long-term debt retirement. 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 2008, 2009 and 2010 are approximately $1.160 million, $1.120 billion and $1.160 billion, 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 a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent. 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.

Over the long-term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in the Carolinas towards the end of the next decade. This approach will require PEC to make significant capital investments. See "Introduction – Strategy" for additional information. These anticipated capital investments are expected to be funded through a combination of long-term debt, and preferred stock, which is dependent on our ability to successfully access capital markets. PEC may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

At December 31, 2007, the current portion of PEC's long-term debt was $300 million, which PEC expects to fund with long-term debt.

CAPITALIZATION RATIOS

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

	2007	2006
Common stock equity	**50.6%**	47.6%
Preferred stock	**0.8%**	0.8%
Total debt	**48.6%**	51.6%

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy, "Contractual Obligations" below, and Notes 22A, 22B and 22C for information on PEC's off-balance sheet arrangements and contractual obligations at December 31, 2007.

GUARANTEES

See discussion under Progress Energy and Note 22C for a discussion of PEC's guarantees.

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 17 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 actual amounts will likely differ from amounts presented below. 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, 2007, 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)	$ 3,491	$ 300	$ 406	$ 500	$ 2,285
Interest payments on long-term debt (b)	1,768	182	311	292	983
Capital lease obligations (See Note 22B)	21	2	5	4	10
Operating leases (See Note 22B)	235	35	47	26	127
Fuel and purchased power (c) (See Note 22A)	5,078	1,043	1,581	938	1,516
Other purchase obligations (See Note 22A)	171	110	41	7	13
Minimum pension funding requirements (d)	83	24	44	15	–
Uncertain tax positions (e) (See Note 14)	–	–	–	–	–
Other commitments (f)	131	13	26	26	66
Total	$ 10,978	$ 1,709	$ 2,461	$ 1,808	$ 5,000

(a) PEC's maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2007.

(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) Uncertain tax positions of $41 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the twelve-month period ending December 31, 2008.

(f) In 2008, PEC must begin transitioning North Carolina jurisdictional 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.

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 "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" 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 July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings.

On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

On December 13, 2007, PEF filed a shelf registration with the SEC, which became effective with the SEC on January 8, 2008. The registration statement will allow PEF to issue up to $4 billion in first mortgage bonds, debt securities and preferred stock in addition to $250 million of previously registered but unsold securities.

See discussion of PEF's credit ratings in Progress Energy "Credit Rating Matters."

PEF expects to have sufficient resources to meet its future obligations through a combination of internally generated funds, commercial paper borrowings, money pool borrowings, its credit facilities, long-term debt, preferred stock and/or contribution of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

Cash provided by operating activities for 2007 decreased when compared with 2006. The $94 million decrease in operating cash flow was primarily due to a $335 million decrease in the recovery of fuel costs driven by the 2006 recovery of previously under-recovered fuel costs. This decrease was partially offset by $93 million from the change in inventory, $47 million in net refunds of cash collateral previously paid to counterparties on derivative contracts in the current year compared to $47 million in net cash payments in the prior year, and $59 million related to a federal income tax refund received in 2007. The increase in operating cash from inventory was principally driven by higher coal inventory purchases in the prior year.

Cash provided by operating activities for 2006 increased when compared with 2005. The $463 million increase in operating cash flow was primarily due to a $577 million increase in the recovery of fuel costs and $72 million related to recovery of storm restoration costs. 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" under Progress Energy above and Note 7C. These impacts were partially offset by a $94 million increase in inventory levels, primarily related to coal, a $49 million decrease from the change in accounts payable, and a $40 million decrease in derivative premiums received.

In 2007, cash used by investing activities increased $667 million when compared with 2006. The increase in cash used by investing activities was primarily due to a $487 million increase in capital expenditures for utility property additions, a $149 million increase in advances to affiliated companies, and a $32 million increase in nuclear fuel additions. The increase in utility property additions is primarily due to environmental compliance projects; repowering the Bartow plant to more efficient natural gas-burning technology, which will not be completed until 2009; and nuclear projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility, as discussed below.

In 2006, cash used by investing activities increased $229 million when compared with 2005. The increase in cash used in investing activities was primarily due to a $231 million increase in capital expenditures for utility property additions. The increase in utility property was primarily due to repowering the Bartow plant to more efficient natural gas-burning technology, various distribution, transmission and steam production projects, and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. Additionally, proceeds from other investing activities were lower in 2006 as compared to 2005 due to $42 million in proceeds from the sale of distribution assets to Winter Park in 2005 (See Notes 3K and 7C). These impacts were partially offset by a $35 million decrease in nuclear fuel additions related to the nuclear facility refueling outage in 2005.

Net cash provided by financing activities increased $956 million for 2007 when compared to 2006, primarily due to the issuance of $750 million of long-term debt in 2007 and dividends paid to the parent of $234 million in 2006. See the discussion above for Progress Energy under "Financing Activities" for information regarding PEF's financing activities.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2008, 2009 and 2010 are approximately $1.640 billion, $1.710 billion and $1.590 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and add environmental control facilities as discussed above in "Capital Expenditures" under Progress Energy.

PEF expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent. 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.

Over the long-term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in Florida towards the end of the next decade. This approach will require PEF to make significant capital investments. See "Introduction – Strategy – Regulated Utilities" for additional information. These anticipated capital investments are expected to be funded through a combination of long-term debt, and preferred stock, which is dependent on our ability to successfully access capital markets. PEF may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

At December 31, 2007, the current portion of PEF's long-term debt was $532 million, which PEF expects to fund through a combination of cash from operations, commercial paper borrowings, money pool borrowings, its credit facilities, long-term debt, preferred stock and/or contribution of equity from the Parent.

CAPITALIZATION RATIOS

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

	2007	2006
Common stock equity	**48.0%**	50.5%
Preferred stock	**0.5%**	0.6%
Total debt	**51.5%**	48.9%

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy and Notes 22A, 22B and 22C for information on PEF's off-balance sheet arrangements and contractual obligations at December 31, 2007.

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 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

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 17).

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.

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.

PROGRESS ENERGY

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 at the end of the reporting period using the Bloomberg Financial Markets system.

In accordance with SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133), interest rate derivatives that qualify as hedges are separated 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, 2007 and 2006, 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 Florida Progress-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 2008 to 2012 and thereafter and the related fair value. 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 17 for more information on interest rate derivatives.

December 31, 2007 (dollars in millions)	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value December 31, 2007
Fixed-rate long-term debt	**$ 427**	**$ 400**	**$ 306**	**$ 1,000**	**$ 950**	**$ 4,865**	**$ 7,948**	**$ 8,192**
Average interest rate	**6.67%**	**5.95%**	**4.53%**	**6.96%**	**6.67%**	**6.03%**	**6.20%**	
Variable-rate long-term debt	**$ 450**	**–**	**$ 100**	**–**	**–**	**$ 861**	**$ 1,411**	**$ 1,411**
Average interest rate	**5.27%**	**–**	**5.69%**	**–**	**–**	**4.45%**	**4.80%**	
Debt to affiliated trust (a)	**–**	**–**	**–**	**–**	**–**	**$ 309**	**$ 309**	**$ 294**
Interest rate	**–**	**–**	**–**	**–**	**–**	**7.10%**	**7.10%**	
Interest rate derivatives								
Interest rate forward contracts (b)	**$ 200**	**–**	**–**	**–**	**–**	**–**	**$ 200**	**$ (12)**
Average pay rate	**5.41%**	**–**	**–**	**–**	**–**	**–**	**5.41%**	
Average receive rate	**(c)**	**–**	**–**	**–**	**–**	**–**	**(c)**	

(a) FPC Capital I – Quarterly Income Preferred Securities.

(b) $100 million is for anticipated 10-year debt issue hedge maturing on April 1, 2018, and requires mandatory cash settlement on April 1, 2008. The remaining $100 million is for anticipated 30-year debt issue hedge maturing on April 1, 2038, and requires mandatory cash settlement on April 1, 2008.

(c) Rate is 3-month London Inter Bank Offering Rate (LIBOR), which was 4.70% at December 31, 2007.

During 2007, PEF had entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, which were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017.

On July 30, 2007, PEC entered into a $50 million notional forward starting swap and on October 24, 2007, PEC entered into $100 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. On September 25, 2007, PEC amended its 10-year forward starting swap in order to move the maturity date from October 1, 2017, to April 1, 2018.

On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2006 (dollars in millions)	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value December 31, 2006
Fixed-rate long-term debt	$ 324	$ 427	$ 400	$ 306	$ 1,000	$ 5,065	$ 7,522	$ 7,820
Average interest rate	6.79%	6.67%	5.95%	4.53%	6.96%	6.13%	6.23%	
Variable-rate long-term debt	–	$ 450	–	$ 100	–	$ 861	$ 1,411	$ 1,411
Average interest rate	–	5.77%	–	5.82%	–	3.62%	4.47%	
Debt to affiliated trust (a)	–	–	–	–	–	$ 309	$ 309	$ 312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	–	–	$ (50)	–	$ (50)	$ (1)
Average pay rate	–	–	–	–	(b)	–	(b)	
Average receive rate	–	–	–	–	4.65%	–	4.65%	
Interest rate forward contracts (c)	$ 100	–	–	–	–	–	$ 100	$ (2)
Average pay rate	5.61%	–	–	–	–	–	5.61%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) FPC Capital I – Quarterly Income Preferred Securities.

(b) Rate is 3-month LIBOR, which was 5.36% at December 31, 2006.

(c) Anticipated 10-year debt issue hedges matured on October 1, 2017, and required mandatory cash settlement on October 1, 2007.

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

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, 2007 and 2006, the fair value of these funds was $1.384 billion and $1.287 billion, respectively, including $804 million and $735 million, respectively, for PEC and $580 million and $552 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 Florida Progress, 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 fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. The CVOs are derivatives and are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively. A hypothetical 10 percent decrease in the December 31, 2007, market price would result in a $3 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, most of our long-term power sales contracts shift substantially all fuel price risk to the purchaser. We also have oil price risk exposure related to synthetic fuels tax credits as discussed in MD&A – "Other Matters – Synthetic Fuels Tax Credits."

Most of our physical commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2007, the only derivative commodity instruments not eligible for recovery from ratepayers related to derivative contracts entered into on January 8, 2007, to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices as discussed below. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. At December 31, 2006, derivative commodity instruments not eligible for recovery from ratepayers were included in discontinued operations as discussed below.

See Note 17 for additional information with regard to our commodity contracts and use of derivative financial instruments.

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of the Georgia Contracts, forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative
instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil 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.

The Utilities have derivative instruments related to their 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 on the Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC’s net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our or the Utilities' results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

PEC designates 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 power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. PEF did not have any commodity derivative instruments designated as cash flow hedges at December 31, 2007 and 2006. At December 31, 2007 and 2006, we and PEC did not have material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2007, 2006 and 2005.

At December 31, 2007 and 2006, the amount recorded in our or PEC's accumulated other comprehensive income related to commodity cash flow hedges was not material. PEF had no amount recorded in accumulated other comprehensive income related to commodity cash flow hedges at December 31, 2007 or 2006.

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 December 31, 2007 and 2006, about PEC's interest rate risk sensitive instruments:

December 31, 2007 (dollars in millions)	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**Fair Value December 31, 2007**
Fixed-rate long-term debt	**$ 300**	**$ 400**	**$ 6**	**$ –**	**$ 500**	**$ 1,665**	**$ 2,871**	**$ 2,925**
Average interest rate	**6.65%**	**5.95%**	**6.30%**	**–**	**6.50%**	**5.57%**	**5.90%**	
Variable-rate long-term debt	**–**	**–**	**–**	**–**	**–**	**$ 620**	**$ 620**	**$ 620**
Average interest rate	**–**	**–**	**–**	**–**	**–**	**4.51%**	**4.51%**	
Interest rate forward contracts (a)	**$ 200**	**–**	**–**	**–**	**–**	**–**	**$ 200**	**$ (12)**
Average pay rate	**5.41%**	**–**	**–**	**–**	**–**	**–**	**5.41%**	
Average receive rate	**(b)**	**–**	**–**	**–**	**–**	**–**	**(b)**	

(a) $100 million is for anticipated 10-year debt issue hedge maturing on April 1, 2018, and requires mandatory cash settlement on April 1, 2008. The remaining $100 million is for anticipated 30-year debt issue hedge maturing on April 1, 2038, and requires mandatory cash settlement on April 1, 2008.

(b) Rate is 3-month LIBOR, which was 4.70% at December 31, 2007.

December 31, 2006 (dollars in millions)	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value December 31, 2006

Fixed-rate long-term debt	$ 200	$ 300	$ 400	$ 6	–	$ 2,165	$ 3,071	$ 3,112
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	–	–	–	–	–	3.61%	3.61%	
Interest rate forward contracts (a)	$ 50	–	–	–	–	–	$ 50	$ (1)
Average pay rate	5.61%	–	–	–	–	–	5.61%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) Anticipated 10-year debt issue hedge matured on October 1, 2017, and required mandatory cash settlement on October 1, 2007.

(b) Rate is 3-month LIBOR, which was 5.36% at December 31, 2006.

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 17 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 December 31, 2007 and 2006, about PEF's interest rate risk sensitive instruments:

December 31, 2007 (dollars in millions)	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**Fair Value December 31, 2007**
Fixed-rate long-term debt	**$ 82**	**$ –**	**$ 300**	**$ 300**	**$ –**	**$ 1,850**	**$ 2,532**	**$ 2,548**
Average interest rate	**6.87%**	**–**	**4.50%**	**6.65%**	**–**	**5.69%**	**5.70%**	
Variable-rate long-term debt	**$ 450**	**–**	**–**	**–**	**–**	**$ 241**	**$ 691**	**$ 691**
Average interest rate	**5.27%**	**–**	**–**	**–**	**–**	**4.32%**	**4.94%**	

December 31, 2006 (dollars in millions)	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value December 31, 2006
Fixed-rate long-term debt	$ 89	$ 82	–	$ 300	$ 300	$ 1,100	$ 1,871	$ 1,876
Average interest rate	6.80%	6.87%	–	4.50%	6.65%	5.37%	5.57%	
Variable-rate long-term debt	–	$ 450	–	–	–	$ 241	$ 691	$ 691
Average interest rate	–	5.77%	–	–	–	3.66%	5.04%	
Interest rate forward contracts (a)	$ 50	–	–	–	–	–	$ 50	$ (1)
Average pay rate	5.61%	–	–	–	–	–	5.61%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) Anticipated 10-year debt issue hedge matured on October 1, 2017, and required mandatory cash settlement on October 1, 2007.

(b) Rate is 3-month LIBOR, which was 5.36% at December 31, 2006.

During 2007, PEF had entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, which were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017.

On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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 17 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 22 and 24
PEF	1 through 3, 5 through 10, 12 through 14, 16 through 22 and 24

Consolidated Financial Statement Schedules for the Years Ended December 31, 2007, 2006 and 2005:

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, 2007 and 2006, 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, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 and Note 16 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting at December 31, 2007, 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 February 28, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data)

Years ended December 31	2007	2006	2005
Operating revenues	**$ 9,153**	$ 8,724	$ 7,948
Operating expenses			
Fuel used in electric generation	**3,145**	3,008	2,359
Purchased power	**1,184**	1,100	1,048
Operation and maintenance	**1,842**	1,583	1,770
Depreciation and amortization	**905**	1,011	926
Taxes other than on income	**501**	500	460
Other	**30**	35	(3)
Total operating expenses	**7,607**	7,237	6,560
Operating income	**1,546**	1,487	1,388
Other income (expense)			
Interest income	**34**	59	13
Other, net	**44**	(16)	(1)
Total other income	**78**	43	12
Interest charges			
Net interest charges	**605**	631	588
Allowance for borrowed funds used during construction	**(17)**	(7)	(13)
Total interest charges, net	**588**	624	575
Income from continuing operations before income tax and minority interest	**1,036**	906	825
Income tax expense	**334**	339	298
Income from continuing operations before minority interest	**702**	567	527
Minority interest in subsidiaries' income, net of tax	**(9)**	(16)	(4)
Income from continuing operations	**693**	551	523
Discontinued operations, net of tax	**(189)**	20	173
Cumulative effect of change in accounting principle, net of tax	**–**	–	1
Net income	**$ 504**	$ 571	$ 697
Average common shares outstanding – basic	**256**	250	247
Basic earnings per common share			
Income from continuing operations	**$ 2.71**	$ 2.20	$ 2.12
Discontinued operations, net of tax	**(0.74)**	0.08	0.70
Net income	**$ 1.97**	$ 2.28	$ 2.82
Diluted earnings per common share			
Income from continuing operations	**$ 2.70**	$ 2.20	$ 2.12
Discontinued operations, net of tax	**(0.74)**	0.08	0.70
Net income	**$ 1.96**	$ 2.28	$ 2.82
Dividends declared per common share	**$ 2.45**	$ 2.43	$ 2.38

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

PROGRESS ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(in millions)

December 31	2007	2006
ASSETS		
Utility plant		
Utility plant in service	$ 25,327	$ 23,743
Accumulated depreciation	(10,895)	(10,064)
Utility plant in service, net	14,432	13,679
Held for future use	37	10
Construction work in progress	1,765	1,289
Nuclear fuel, net of amortization	371	267
Total utility plant, net	16,605	15,245
Current assets		
Cash and cash equivalents	255	265
Short-term investments	1	71
Receivables, net	1,137	930
Inventory	994	936
Deferred fuel cost	154	196
Deferred income taxes	27	142
Assets to be divested	52	966
Prepayments and other current assets	155	108
Total current assets	2,775	3,614
Deferred debits and other assets		
Regulatory assets	931	1,231
Nuclear decommissioning trust funds	1,384	1,287
Miscellaneous other property and investments	448	465
Goodwill	3,655	3,655
Derivative assets	109	2
Other assets and deferred debits	379	208
Total deferred debits and other assets	6,906	6,848
Total assets	$ 26,286	$ 25,707
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 260 and 256 million shares issued and outstanding, respectively	$ 6,028	$ 5,791
Unearned ESOP shares (2 million shares)	(37)	(50)
Accumulated other comprehensive loss	(34)	(49)
Retained earnings	2,465	2,594
Total common stock equity	8,422	8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93
Minority interest	84	10
Long-term debt, affiliate	271	271
Long-term debt, net	8,466	8,564
Total capitalization	17,336	17,224
Current liabilities		
Current portion of long-term debt	877	324
Short-term debt	201	–
Accounts payable	789	712
Interest accrued	173	171
Dividends declared	160	156
Customer deposits	255	227
Regulatory liabilities	173	76
Liabilities to be divested	8	248
Income taxes accrued	8	284
Other current liabilities	604	622
Total current liabilities	3,248	2,820
Deferred credits and other liabilities		

Noncurrent income tax liabilities	**361**	312
Accumulated deferred investment tax credits	**139**	151
Regulatory liabilities	**2,539**	2,543
Asset retirement obligations	**1,378**	1,304
Accrued pension and other benefits	**763**	957
Capital lease obligations	**239**	70
Other liabilities and deferred credits	**283**	326
Total deferred credits and other liabilities	**5,702**	5,663
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$ 26,286**	$ 25,707

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)

Years ended December 31	**2007**	2006	2005
Operating activities			
Net income	**$ 504**	$ 571	$ 697
Adjustments to reconcile net income to net cash provided by operating activities			
Impairment of assets	**–**	174	–
Charges for voluntary enhanced retirement program	**–**	–	159
Depreciation and amortization	**1,026**	1,190	1,216
Deferred income taxes and investment tax credits, net	**177**	(251)	(340)
Deferred fuel cost (credit)	**117**	396	(317)
Deferred income	**(128)**	(69)	–
Other adjustments to net income	**124**	88	135
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(193)**	78	(170)
Inventory	**(11)**	(168)	(163)
Prepayments and other current assets	**23**	(92)	(13)
Income taxes, net	**(275)**	197	101
Accounts payable	**(34)**	16	124
Other current liabilities	**150**	(30)	65
Other assets and deferred debits	**(221)**	(60)	(78)
Other liabilities and deferred credits	**(7)**	(39)	51
Net cash provided by operating activities	**1,252**	2,001	1,467
Investing activities			
Gross property additions	**(1,973)**	(1,572)	(1,313)
Nuclear fuel additions	**(228)**	(114)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**675**	1,657	475
Purchases of available-for-sale securities and other investments	**(1,413)**	(2,452)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	**1,452**	2,631	3,845
Other investing activities	**30**	(23)	(40)
Net cash (used) provided by investing activities	**(1,457)**	127	(1,144)
Financing activities			
Issuance of common stock	**151**	185	208
Dividends paid on common stock	**(627)**	(607)	(582)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	**176**	–	–
Net increase (decrease) in short-term debt	**25**	(175)	(509)
Proceeds from issuance of long-term debt, net	**739**	397	1,642
Retirement of long-term debt	**(324)**	(2,200)	(564)
Other financing activities	**55**	(68)	32
Net cash provided (used) by financing activities	**195**	(2,468)	227
Net (decrease) increase in cash and cash equivalents	**(10)**	(340)	550
Cash and cash equivalents at beginning of year	**265**	605	55
Cash and cash equivalents at end of year	**$ 255**	$ 265	$ 605
Supplemental disclosures			
Cash paid during the year			
Interest (net of amount capitalized)	**$ 585**	$ 698	$ 645
Income taxes (net of refunds)	**176**	311	168
Significant noncash transactions			
Capital lease obligation incurred	**182**	54	–
Note receivable for disposal of ownership interest in Ceredo	**48**	–	–
Noncash property additions accrued for as of December 31	**329**	231	116

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions)	Common Stock Outstanding Shares	Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
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 No.							
123R adoption		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		13	–	–	–	–	13
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	252	5,571	–	(63)	(104)	2,634	8,038
Net income		–	–	–	–	571	571
Other comprehensive loss		–	–	–	(18)	–	(18)
Comprehensive income							553
Adjustment to initially apply SFAS							
No. 158, net of tax		–	–	–	73	–	73
Issuance of shares	4	70	–	–	–	–	70
Stock options exercised		115	–	–	–	–	115
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		13	–	13	–	–	26
Stock-based compensation expense		30	–	–	–	–	30
Dividends ($2.43 per share)		–	–	–	–	(611)	(611)
Balance, December 31, 2006	**256**	**5,791**	**–**	**(50)**	**(49)**	**2,594**	**8,286**
Net income		**–**	**–**	**–**	**–**	**504**	**504**
Other comprehensive income		**–**	**–**	**–**	**15**	**–**	**15**
Comprehensive income							**519**
Adjustment to initially apply FASB							
Interpretation No. 48		**–**	**–**	**–**	**–**	**(2)**	**(2)**
Issuance of shares	**4**	**46**	**–**	**–**	**–**	**–**	**46**
Stock options exercised		**105**	**–**	**–**	**–**	**–**	**105**
Allocation of ESOP shares		**15**	**–**	**13**	**–**	**–**	**28**
Stock-based compensation expense		**71**	**–**	**–**	**–**	**–**	**71**
Dividends ($2.45 per share)		**–**	**–**	**–**	**–**	**(631)**	**(631)**
Balance, December 31, 2007	**260**	**$6,028**	**$–**	**$(37)**	**$(34)**	**$2,465**	**$8,422**

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions)

Years ended December 31	2007	2006	2005
Net income	**$ 504**	$ 571	$ 697
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax (expense) benefit of $(3), $28 and $(26), respectively)	**4**	(46)	46
Foreign currency translation adjustments included in discontinued operations	**–**	–	(6)
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	**–**	–	1
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $1)	**2**	–	–
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $8, $16 and $(26), respectively)	**(13)**	(23)	37
Net unrecognized items on pension and other postretirement benefits (net of tax expense of $16)	**23**	–	–
Minimum pension liability adjustment (net of tax (expense) benefit of $(30) and $22, respectively)	**–**	48	(19)
Other (net of tax benefit (expense) of $3, $- and $(1), respectively)	**(1)**	3	1
Other comprehensive income (loss)	**15**	(18)	60
Comprehensive income	**$ 519**	$ 553	$ 757

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, 2007 and 2006, 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, 2007. 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. Our audits include 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, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 and Note 16 to the consolidated financial statements, on January 1, 2007, PEC adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006, PEC adopted Statement of Financial Accounting Standards No. 158.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

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

CONSOLIDATED STATEMENTS of INCOME

(in millions)

Years ended December 31	**2007**	2006	2005
Operating revenues	**$ 4,385**	$ 4,086	$ 3,991
Operating expenses			
Fuel used in electric generation	**1,381**	1,173	1,036
Purchased power	**302**	334	354
Operation and maintenance	**1,024**	930	941
Depreciation and amortization	**519**	571	561
Taxes other than on income	**192**	191	178
Other	**(2)**	–	(10)
Total operating expenses	**3,416**	3,199	3,060
Operating income	**969**	887	931
Other income (expense)			
Interest income	**21**	25	8
Other, net	**16**	25	(15)
Total other income (expense)	**37**	50	(7)
Interest charges			
Interest charges	**215**	217	197
Allowance for borrowed funds used during construction	**(5)**	(2)	(5)
Total interest charges, net	**210**	215	192
Income before income tax	**796**	722	732
Income tax expense	**295**	265	239
Net income	**501**	457	493
Preferred stock dividend requirement	**3**	3	3
Earnings for common stock	**$ 498**	$ 454	$ 490

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	**2007**	2006
ASSETS		
Utility plant		
Utility plant in service	**$ 15,117**	$ 14,356
Accumulated depreciation	**(7,097)**	(6,408)
Utility plant in service, net	**8,020**	7,948
Held for future use	**2**	3
Construction work in progress	**566**	617
Nuclear fuel, net of amortization	**292**	209
Total utility plant, net	**8,880**	8,777
Current assets		
Cash and cash equivalents	**25**	71
Short-term investments	**1**	50
Receivables, net	**472**	473
Receivables from affiliated companies	**42**	27
Notes receivable from affiliated companies	**–**	24
Inventory	**510**	497
Deferred fuel cost	**148**	196
Prepayments and other current assets	**49**	45
Total current assets	**1,247**	1,383
Deferred debits and other assets		
Regulatory assets	**679**	777
Nuclear decommissioning trust funds	**804**	735
Miscellaneous other property and investments	**192**	193
Other assets and deferred debits	**160**	155
Total deferred debits and other assets	**1,835**	1,860
Total assets	**$ 11,962**	$ 12,020
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	**$ 2,054**	$ 2,010
Unearned ESOP common stock	**(37)**	(50)
Accumulated other comprehensive loss	**(10)**	(1)
Retained earnings	**1,772**	1,431
Total common stock equity	**3,779**	3,390
Preferred stock – not subject to mandatory redemption	**59**	59
Long-term debt, net	**3,183**	3,470
Total capitalization	**7,021**	6,919
Current liabilities		
Current portion of long-term debt	**300**	200
Notes payable to affiliated companies	**154**	–
Accounts payable	**290**	310
Payables to affiliated companies	**71**	108
Interest accrued	**58**	69
Customer deposits	**70**	59
Income taxes accrued	**27**	68
Current portion of unearned revenue	**3**	71
Other current liabilities	**178**	154
Total current liabilities	**1,151**	1,039
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**936**	909
Accumulated deferred investment tax credits	**122**	128
Regulatory liabilities	**1,097**	1,320
Asset retirement obligations	**1,063**	1,004

Accrued pension and other benefits		**459**		581
Other liabilities and deferred credits		**113**		120
Total deferred credits and other liabilities		**3,790**		4,062
Commitments and contingencies (Notes 21 and 22)				
Total capitalization and liabilities	**$**	**11,962**	$	12,020

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	**2007**	2006	2005
Operating activities			
Net income	**$ 501**	$ 457	$ 493
Adjustments to reconcile net income to net cash provided by operating activities			
Charges for voluntary enhanced retirement program	**–**	–	42
Depreciation and amortization	**608**	656	644
Deferred income taxes and investment tax credits, net	**41**	(59)	(150)
Deferred fuel cost (credit)	**48**	(8)	(144)
Other adjustments to net income	**(47)**	(23)	69
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(19)**	36	(111)
Receivables from affiliated companies	**(15)**	9	11
Inventory	**(10)**	(69)	(91)
Prepayments and other current assets	**(17)**	10	9
Income taxes, net	**(37)**	(24)	163
Accounts payable	**36**	56	9
Payables to affiliated companies	**(37)**	32	(13)
Other current liabilities	**(29)**	(16)	76
Other assets and deferred debits	**(28)**	38	(19)
Other liabilities and deferred credits	**23**	(1)	44
Net cash provided by operating activities	**1,018**	1,094	1,032
Investing activities			
Gross property additions	**(757)**	(705)	(603)
Nuclear fuel additions	**(184)**	(102)	(79)
Purchases of available-for-sale securities and other investments	**(603)**	(896)	(1,832)
Proceeds from sales of available-for-sale securities and other investments	**622**	1,006	1,692
Changes in advances to affiliated companies	**24**	(24)	–
Other investing activities	**6**	(1)	11
Net cash used by investing activities	**(892)**	(722)	(811)
Financing activities			
Dividends paid on preferred stock	**(3)**	(3)	(3)
Dividends paid to parent	**(143)**	(339)	(457)
Net decrease in short-term debt	**–**	(73)	(148)
Proceeds from issuance of long-term debt, net	**–**	–	898
Retirement of long-term debt	**(200)**	–	(300)
Changes in advances from affiliated companies	**154**	(11)	(105)
Other financing activities	**20**	–	1
Net cash used by financing activities	**(172)**	(426)	(114)
Net (decrease) increase in cash and cash equivalents	**(46)**	(54)	107
Cash and cash equivalents at beginning of year	**71**	125	18
Cash and cash equivalents at end of year	**$ 25**	$ 71	$ 125
Supplemental disclosures			
Cash paid during the year			
Interest (net of amount capitalized)	**$ 210**	$ 210	$ 187
Income taxes (net of refunds)	**291**	347	222
Significant noncash transactions			
Noncash property additions accrued for as of December 31	**87**	104	53

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)	Common Stock Outstanding Shares	Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
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
Net income		–	–	–	457	457
Other comprehensive income		–	–	36	–	36
Comprehensive income						493
Adjustment to initially apply SFAS No. 158, net of tax		–	–	83	–	83
Stock-based compensation expense		10	–	–	–	10
Allocation of ESOP shares		19	13	–	–	32
Preferred stock dividends at stated rates		–	–	–	(3)	(3)
Dividends paid to parent		–	–	–	(339)	(339)
Tax benefit dividend		–	–	–	(4)	(4)
Balance, December 31, 2006	**160**	**2,010**	**(50)**	**(1)**	**1,431**	**3,390**
Net income		**–**	**–**	**–**	**501**	**501**
Other comprehensive loss		**–**	**–**	**(9)**	**–**	**(9)**
Comprehensive income						**492**
Adjustment to initially apply FASB Interpretation No. 48		**–**	**–**	**–**	**(6)**	**(6)**
Stock-based compensation expense		**24**	**–**	**–**	**–**	**24**
Allocation of ESOP shares		**20**	**13**	**–**	**–**	**33**
Preferred stock dividends at stated rates		**–**	**–**	**–**	**(3)**	**(3)**
Dividends paid to parent		**–**	**–**	**–**	**(143)**	**(143)**
Tax benefit dividend		**–**	**–**	**–**	**(8)**	**(8)**
Balance, December 31, 2007	**160**	**$ 2,054**	**$ (37)**	**$ (10)**	**$ 1,772**	**$ 3,779**

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

(in millions) Years ended December 31	**2007**	2006	2005
Net income	**$501**	$457	$493
Other comprehensive (loss) income			
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $4, $2, and $(2), respectively)	**(5)**	(2)	3
Reclassification adjustment included in net income (net of tax expense of $-)	**–**	–	1

Minimum pension liability adjustment (net of tax (expense) benefit of $(23) and $7, respectively)	**–**	36	(12)
Other (net of tax benefit (expense) of $1, $1, and $(1), respectively)	**(4)**	2	2
Other comprehensive (loss) income	**(9)**	36	(6)
Comprehensive income	**$492**	$493	$487

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, 2007 and 2006, and the related 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, 2007. 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. Our audits include 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, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 and Note 16 to the financial statements, on January 1, 2007, PEF adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006, PEF adopted Statement of Financial Accounting Standards No. 158.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of INCOME

(in millions)

Years ended December 31		**2007**		2006		2005
Operating revenues	**$**	**4,749**	$	4,639	$	3,955
Operating expenses						
Fuel used in electric generation		**1,764**		1,835		1,323
Purchased power		**882**		766		694
Operation and maintenance		**834**		684		852
Depreciation and amortization		**366**		404		334
Taxes other than on income		**309**		309		279
Other		**8**		(2)		(26)
Total operating expenses		**4,163**		3,996		3,456
Operating income		**586**		643		499
Other income						
Interest income		**9**		15		1
Other, net		**39**		13		7
Total other income		**48**		28		8
Interest charges						
Interest charges		**185**		155		134
Allowance for borrowed funds used during construction		**(12)**		(5)		(8)
Total interest charges, net		**173**		150		126
Income before income tax		**461**		521		381
Income tax expense		**144**		193		121
Net income		**317**		328		260
Preferred stock dividend requirement		**2**		2		2
Earnings for common stock	**$**	**315**	$	326	$	258

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

BALANCE SHEETS

(in millions)

December 31	2007	2006
ASSETS		
Utility plant		
Utility plant in service	**$ 10,025**	$ 9,202
Accumulated depreciation	**(3,738)**	(3,602)
Utility plant in service, net	**6,287**	5,600
Held for future use	**35**	7
Construction work in progress	**1,199**	672
Nuclear fuel, net of amortization	**79**	58
Total utility plant, net	**7,600**	6,337
Current assets		
Cash and cash equivalents	**23**	23
Receivables, net	**339**	340
Receivables from affiliated companies	**8**	11
Notes receivable from affiliated companies	**149**	–
Deferred income taxes	**39**	86
Inventory	**484**	436
Income taxes receivable	**41**	47
Derivative assets	**60**	–
Prepayments and other current assets	**9**	62
Total current assets	**1,152**	1,005
Deferred debits and other assets		
Regulatory assets	**252**	454
Nuclear decommissioning trust funds	**580**	552
Miscellaneous other property and investments	**46**	45
Derivative assets	**90**	2
Prepaid pension cost	**221**	174
Other assets and deferred debits	**63**	24
Total deferred debits and other assets	**1,252**	1,251
Total assets	**$ 10,004**	$ 8,593
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$ 1,109**	$ 1,100
Accumulated other comprehensive loss	**(8)**	(1)
Retained earnings	**1,901**	1,588
Total common stock equity	**3,002**	2,687
Preferred stock – not subject to mandatory redemption	**34**	34
Long-term debt, net	**2,686**	2,468
Total capitalization	**5,722**	5,189
Current liabilities		
Current portion of long-term debt	**532**	89
Notes payable to affiliated companies	**–**	47
Accounts payable	**461**	292
Payables to affiliated companies	**87**	116
Interest accrued	**57**	38
Customer deposits	**185**	168
Derivative liabilities	**15**	89
Regulatory liabilities	**173**	76
Other current liabilities	**92**	89
Total current liabilities	**1,602**	1,004
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**401**	466
Accumulated deferred investment tax credits	**17**	23
Regulatory liabilities	**1,316**	1,091
Asset retirement obligations	**315**	299

Accrued pension and other benefits		**304**		332
Capital lease obligations		**224**		53
Other liabilities and deferred credits		**103**		136
Total deferred credits and other liabilities		**2,680**		2,400
Commitments and contingencies (Notes 21 and 22)				
Total capitalization and liabilities	**$**	**10,004**	$	8,593

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of CASH FLOWS

(in millions)

Years ended December 31	**2007**	2006	2005
Operating activities			
Net income	**$ 317**	$ 328	$ 260
Adjustments to reconcile net income to net cash provided by operating activities			
Charges for voluntary enhanced retirement program	**–**	–	92
Depreciation and amortization	**385**	433	367
Deferred income taxes and investment tax credits, net	**(44)**	(48)	(50)
Deferred fuel cost (credit)	**69**	404	(173)
Other adjustments to net income	**36**	19	19
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(11)**	(23)	(70)
Receivables from affiliated companies	**3**	–	4
Inventory	**(35)**	(128)	(34)
Prepayments and other current assets	**72**	(37)	(22)
Income taxes, net	**3**	(56)	(14)
Accounts payable	**46**	3	52
Payables to affiliated companies	**(29)**	15	21
Other current liabilities	**35**	20	7
Other assets and deferred debits	**(44)**	13	(55)
Other liabilities and deferred credits	**(4)**	(50)	26
Net cash provided by operating activities	**799**	893	430
Investing activities			
Gross property additions	**(1,214)**	(727)	(496)
Nuclear fuel additions	**(44)**	(12)	(47)
Purchases of available-for-sale securities and other investments	**(640)**	(625)	(405)
Proceeds from sales of available-for-sale securities and other investments	**640**	625	405
Changes in advances to affiliated companies	**(149)**	–	–
Other investing activities	**5**	4	37
Net cash used by investing activities	**(1,402)**	(735)	(506)
Financing activities			
Dividends paid on preferred stock	**(2)**	(2)	(2)
Dividends paid to parent	**–**	(234)	–
Net decrease in short-term debt	**–**	(102)	(191)
Proceeds from issuance of long-term debt, net	**739**	–	744
Retirement of long-term debt	**(89)**	(48)	(102)
Changes in advances from affiliated companies	**(47)**	34	(165)
Other financing activities	**2**	(1)	(2)
Net cash provided (used) by financing activities	**603**	(353)	282
Net (decrease) increase in cash and cash equivalents	**–**	(195)	206
Cash and cash equivalents at beginning of year	**23**	218	12
Cash and cash equivalents at end of year	**$ 23**	$ 23	$ 218
Supplemental disclosures			
Cash paid during the year			
Interest (net of amount capitalized)	**$ 149**	$ 152	$ 131
Income taxes (net of refunds)	**184**	296	185
Significant noncash transactions			
Capital lease obligation incurred	**182**	54	–
Noncash property additions accrued for as of December 31	**238**	119	50

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Amount	Accumulated Other Comprehensive Loss	Retained Earnings	Total Common Stock Equity
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
Net income		–	–	328	328
Other comprehensive loss		–	(1)	–	(1)
Comprehensive income					327
Stock-based compensation expense		3	–	–	3
Preferred stock dividends at stated rates		–	–	(2)	(2)
Dividends paid to parent		–	–	(234)	(234)
Tax benefit dividend		–	–	(2)	(2)
Balance, December 31, 2006	**100**	**1,100**	**(1)**	**1,588**	**2,687**
Net income		**–**	**–**	**317**	**317**
Other comprehensive loss		**–**	**(7)**	**–**	**(7)**
Comprehensive income					**310**
Stock-based compensation expense		**9**	**–**	**–**	**9**
Preferred stock dividends at stated rates		**–**	**–**	**(2)**	**(2)**
Tax benefit dividend		**–**	**–**	**(2)**	**(2)**
Balance, December 31, 2007	**100**	**$ 1,109**	**$ (8)**	**$ 1,901**	**$ 3,002**

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2007**	2006	2005
Net income	**$ 317**	$ 328	$ 260
Other comprehensive loss			
Net unrealized losses on cash flow hedges (net of tax benefit of $5 and $1, respectively)	**(7)**	(1)	–
Other comprehensive loss	**(7)**	(1)	–
Comprehensive income	**$ 310**	$ 327	$ 260

See Notes to PEF 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. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company (PESC) and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment.

See Note 19 for further information about our segments.

PEC

PEC is a regulated public utility 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), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility 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 and the FERC.

B. BASIS OF PRESENTATION

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

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies (generally 20 percent to 50 percent ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20). 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.

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 2006 and 2005 have been reclassified to conform to the 2007 presentation. In addition, our 2007 presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, "Statement of Cash Flows." Previously, we had provided separate disclosure of cash flows from continuing operations and discontinued operations. These changes in cash flow presentations had no impact on total cash and cash equivalents, net change in cash and cash equivalents, or results of operations.

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 46R).

PROGRESS ENERGY

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several 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, 2007, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $6 million, which represents our net remaining investment in the 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 Internal Revenue Code (the Code). At December 31, 2007, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheet.

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, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows.

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 $39 million, $45 million and $44 million in 2007, 2006 and 2005, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (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 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 21 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2007, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $19 million, which primarily represents its 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 four variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one limited liability corporation, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2007, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $56 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. 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, and diversified business revenues, which are generally recognized at the time products are shipped or as services are rendered. 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 other recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs, fuel-related 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 sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Progress Energy	**$ 299**	$ 293	$ 258
PEC	**99**	94	91
PEF	**200**	199	167

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," 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." Effective July 1, 2005, we adopted the fair value recognition provisions of SFAS No. 123R, “Share-Based Payment” (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 PUHCA 2005. 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.

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 (ARO) 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 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

We account for AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. 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. In addition, effective December 31, 2005, we also adopted FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47), which clarified certain requirements of SFAS No. 143.

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

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.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended in December 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility’s last general rate case. There were no adjustments to PEC’s base rates during the five-year period ended December 2007. Subsequent to 2007, PEC’s current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for the amortization and recovery of 70 percent of the original estimated compliance costs for the Clean Smokestacks Act while providing significant flexibility in the amount of annual amortization recorded from none up to \$174 million per year. During 2007, the NCUC approved PEC's request to amortize the remaining 30 percent of the original estimated compliance costs during 2008 and 2009, with discretion to amortize up to \$174 million in either year.

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. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are established for excess and obsolete inventory. We value inventory of nonregulated subsidiaries at the lower of 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.

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 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 fuels tax credits. Since 2002, Progress Energy tax benefits not related to acquisition interest expense had been allocated to profitable subsidiaries in accordance with an order under the Public Utilities Holding Company Act of 1935, as amended (PUHCA 1935). 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 1935, effective February 8, 2006, we stopped 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 fuels are deferred 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) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net on 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," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." 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. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies 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. 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 21, 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. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. 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 or on actual receipt of recovery. 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 impairment 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 impairment 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 in value exists, the investments are written down to fair value with a new cost basis established.

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

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"

Refer to Note 14 for information regarding our first quarter 2007 implementation of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which redefines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." SFAS No. 157 establishes a framework for measuring fair value and a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. The effective date of SFAS No. 157 for us and the Utilities is January 1, 2008. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, which for us and the Utilities delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. We will implement SFAS No. 157 as of January 1, 2008, and will utilize the deferral provision of FSP No. FAS 157-2 for all nonfinancial assets and liabilities within its scope. We do not expect the adoption of SFAS No. 157 to have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115" (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied on an instrument by instrument basis, is irrevocable (unless a new election date occurs) and is applied to the entire financial instrument. SFAS No. 159 is effective for us and the Utilities on January 1, 2008. We do not expect the adoption of SFAS No. 159 to have a material impact on our or the Utilities' financial position or results of operations.

FASB Staff Position FIN No. 39-1, An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts

FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" (FIN 39), specifies what conditions must be met for an entity to have the right to offset assets and liabilities in the balance sheet and clarifies when it is appropriate to offset amounts recognized for forward interest rate swap, currency swap, option and other conditional or exchange contracts. FIN 39 also permits offsetting of fair value amounts recognized for multiple contracts executed with the same counterparty under a master netting arrangement. On April 30, 2007, the FASB issued FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), which amends portions of FIN 39 to make certain terms consistent with those used in SFAS No. 133. FSP FIN 39-1 also amends FIN 39 to allow for the offsetting of fair value amounts for the right to reclaim collateral assets or liabilities arising from the same master netting arrangement as the derivative instruments. We will implement the FSP as of January 1, 2008, as a retrospective change in accounting principle for all financial statements presented. We and the Utilities currently offset fair value amounts recognized for derivative instruments under master netting arrangements. As allowed under FSP FIN 39-1, we and the Utilities will change our accounting policy effective January 1, 2008, and discontinue the offset of fair value amounts for such derivatives. We expect this change in policy to result in increases to total derivative assets and liabilities and accounts receivables and payables of $64 million as of adoption on January 1, 2008, but will have no impact on our or the Utilities' results of operations or equity.

SFAS No. 141R, "Business Combinations"

In December 2007, the FASB issued SFAS Statement No. 141R, "Business Combinations" (SFAS No. 141R), which introduces significant changes in the accounting for business acquisitions. SFAS No. 141R considerably broadens the definition of a "business" and a "business combination," which will result in an increased number of transactions or other events that will qualify as business combinations. This will affect us and the Utilities primarily in our assessment of variable interest entities ("VIEs"). SFAS No. 141R amends FIN 46R to clarify that the initial consolidation of a business that is a VIE is a business combination in which the acquirer should recognize and measure the fair value of the acquiree as a whole, and the assets acquired and liabilities assumed at their full fair values as of the date control is obtained, regardless of the percentage ownership in the acquiree or how the acquisition was achieved. Other significant changes include the expensing of all acquisition-related transaction costs and most acquisition-related restructuring costs, the fair value remeasurement of certain earn-out arrangements and the discontinuance of the expense at acquisition of acquired-in-process research and development. SFAS No. 141R is effective for us for business combinations for which the acquisition date is on or after January 1, 2009. Earlier application is prohibited. We do not expect the adoption of SFAS No. 141R to have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51"

In conjunction with the issuance of SFAS No. 141R, in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" (SFAS No. 160) which introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. SFAS No. 160 also changes the accounting for and reporting for the deconsolidation of a subsidiary. SFAS No. 160 requires that a noncontrolling interest in a consolidated subsidiary be displayed in the consolidated statement of financial position as a separate component of equity rather than as a "mezzanine" item between liabilities and equity. SFAS No. 160 also requires that earnings attributed to the noncontrolling interests be reported as part of consolidated earnings, and requires disclosure of the attribution of consolidated earnings to the controlling and noncontrolling interests on the face of the consolidated income statement. SFAS No. 160 must be adopted concurrently with the effective date of SFAS No. 141R, which for us is January 1, 2009. We do not expect the adoption of SFAS No. 160 to have a material impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

A. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006.

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represents substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represents the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax (charge included in the net loss from discontinued operations in the table below). We used the net proceeds from the divestiture of CCO and the Georgia Contracts for general corporate purposes.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $11 million, $36 million and $39 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during each of the years ended December 31, 2006 and 2005 was $14 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)		**2007**		2006		2005
Revenues	**$**	**407**	$	754	$	627
Loss before income taxes	**$**	**(449)**	$	(92)	$	(93)
Income tax benefit		**166**		35		39
Net loss from discontinued operations		**(283)**		(57)		(54)
Gain (loss) on disposal of discontinued operations, including income tax benefit of $7 and $123, respectively		**18**		(226)		–
Loss from discontinued operations	**$**	**(265)**	$	(283)	$	(54)

B. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously a component of our former Coal and Synthetic Fuels segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Terminals as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during each of the years ended December 31, 2007, 2006 and 2005 was $2 million, $4 million and $7 million, respectively.

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels (Synthetic Fuels) as defined under Section 29 of the Code. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels are generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007. In accordance with the provisions of SFAS No. 144, a long-lived asset is abandoned when it ceases to be used. The accompanying consolidated income statements have been restated for all periods presented to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of discontinued operations for the years ended December 31 for Terminals and Synthetic Fuels were as follows:

(in millions)		**2007**		2006		2005
Revenues	**$**	**1,126**	$	847	$	1,220
Earnings (loss) before income taxes and minority interest	**$**	**2**	$	(179)	$	(171)
Income tax benefit, including tax credits		**64**		135		336
Minority interest share of losses		**17**		7		33
Net earnings (loss) from discontinued operations	**$**	**83**	$	(37)	$	198

C. NATURAL GAS DRILLING AND PRODUCTION

On October 2, 2006, we sold our natural gas drilling and production business (Gas) for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas

Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2006, and 2005 was $13 million. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $16 million and $26 million, respectively. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	$ –	$ 192	$ 159
Earnings before income taxes	$ –	$ 135	$ 73
Income tax benefit (expense)	**4**	(53)	(25)
Net earnings from discontinued operations	**4**	82	48
(Loss) gain on disposal of discontinued operations, including income tax benefit (expense) of $1 and $(188), respectively	**(2)**	300	–
Earnings from discontinued operations	**$ 2**	$ 382	$ 48

D. CCO – DESOTO AND ROWAN GENERATION FACILITIES

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan). DeSoto owned a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes.

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2006, and 2005 was $6 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $3 million and $8 million, respectively. Results of discontinued operations for DeSoto and Rowan for the years ended December 31 were as follows:

(in millions)		2006		2005
Revenues	$	64	$	67
Earnings before income taxes	$	15	$	5
Income tax expense		(5)		(2)
Net earnings from discontinued operations		10		3
Loss on disposal of discontinued operations, including income tax benefit of $37		(67)		–
(Loss) earnings from discontinued operations	$	(57)	$	3

E. PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. (Level 3). We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of approximately $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC. See Note 20 for a discussion of the subsequent sale of the Level 3 stock in 2006.

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax net gain on disposal of $28 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for the year ended December 31, 2005. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $8 million, respectively. Results of discontinued operations for PT LLC for the years ended December 31 were as follows:

(in millions)		2006		2005
Revenues	$	18	$	76
Earnings before income taxes and minority interest	$	7	$	11
Income tax expense		(4)		(3)
Minority interest share of earnings		(5)		(4)
Net (loss) earnings from discontinued operations		(2)		4
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35		28		–
Earnings from discontinued operations	$	26	$	4

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

F. DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications.

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for each of the years ended December 31, 2006, and 2005. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $2 million, respectively. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$ –**	$ 20	$ 32
Earnings before income taxes	**$ –**	$ 11	$ 8
Income tax expense	**–**	(4)	(3)
Net earnings from discontinued operations	**–**	7	5
Gain on disposal of discontinued operations, including income tax expense of $1 and $1, respectively	**2**	2	–
Earnings from discontinued operations	**$ 2**	$ 9	$ 5

G. COAL MINING BUSINESSES

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets.

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements 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. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the year ended December 31, 2005, was $10 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$ 28**	$ 84	$ 184
Loss before income taxes	**$ (17)**	$ (11)	$ (16)
Income tax benefit	**6**	7	5
Net loss from discontinued operations	**(11)**	(4)	(11)
Loss on disposal of discontinued operations, including income tax benefit of $16	**–**	(10)	–
Loss from discontinued operations	**$ (11)**	$ (14)	$ (11)

H. PROGRESS RAIL

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. 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. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

The accompanying consolidated financial statements 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. Pre-tax interest expense allocated for the year ended December 31, 2005, was $4 million. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the year ended December 31, 2005, was $3 million. Results of discontinued operations for Progress Rail for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$ –	$ 358
Earnings before income taxes	$ –	$ 8
Income tax expense	–	(3)
Net earnings from discontinued operations	–	5
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	(6)	(25)
Loss from discontinued operations	$ (6)	$ (20)

I. NET ASSETS TO BE DIVESTED

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of the coal mining operations were included in net assets to be divested. At December 31, 2006, the assets and liabilities of CCO, Terminals, the remaining coal mining operations and other fuels businesses were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2007**	December 31, 2006
Accounts receivable	$ –	$ 44
Inventory	**6**	56
Other current assets	**2**	45
Property, plant and equipment, net	**38**	595
Other assets	**6**	226
Assets to be divested	**$ 52**	$ 966
Accounts payable	$ –	$ 43
Accrued expenses	**3**	179
Long-term liabilities	**5**	26
Liabilities to be divested	**$ 8**	$ 248

J. CEREDO SYNTHETIC FUELS INTERESTS

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo Synfuel LLC (Ceredo), a subsidiary that produces and sells qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a non-recourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying synthetic fuels on behalf of the buyer. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million in 2007 and $5 million in 2008. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. The note bears interest at a rate equal to the three-month London Inter Bank Offering Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million.

Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions discussed below, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FIN 46R, but recorded a 100 percent minority interest. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

K. 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.

L. SYNTHETIC FUELS 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 fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million and $30 million in the years ended December 31, 2006, and 2005, respectively. In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gains. The operations of Colona have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent 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 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. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3C).

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	**2007**	2006	**2007**	2006	**2007**	2006
Production plant	7-43	**$ 13,765**	$ 12,685	**$ 8,968**	$ 8,422	**$ 4,612**	$ 4,078
Transmission plant	17-75	**2,684**	2,509	**1,361**	1,300	**1,323**	1,209
Distribution plant	13-55	**7,676**	7,351	**4,147**	3,992	**3,529**	3,359
General plant and other	5-35	**1,202**	1,198	**641**	642	**561**	556
Utility plant in service		**$ 25,327**	$ 23,743	**$ 15,117**	$ 14,356	**$ 10,025**	$ 9,202

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 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 for certain projects in accordance with the regulatory provisions for each jurisdiction. 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 8.8%, 8.7% and 5.6% in 2007, 2006 and 2005, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8%, 8.8% and 7.8% in 2007, 2006 and 2005, respectively.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.2% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $560 million, $533 million and $477 million in 2007, 2006 and 2005, 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 21) 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, 2007, 2006 and 2005 was $139 million, $140 million and $136 million, respectively. 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 2.1% for 2007, 2006 and 2005. The depreciation provisions related to utility plant were $303 million, $294 million and $286 million in 2007, 2006 and 2005, 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 7B) and Clean Smokestacks Act amortization (See Note 7B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7%, 2.7% and 2.3% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $257 million, $239 million and $191 million in 2007, 2006 and 2005, 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 21). 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, 2007, 2006 and 2005 was $110 million, $109 million and $107 million, respectively, for PEC and $29 million, $31 million and $29 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. DIVERSIFIED BUSINESS PROPERTY

Net diversified business property is included in miscellaneous other property and investments on our and PEC's Consolidated Balance Sheets. Diversified business property excludes amounts reclassified as assets to be divested (See Note 3I).

Progress Energy

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

(in millions)		**2007**		2006
Equipment (3-25 years)	**$**	**6**	$	10
Land and mineral rights		–		1
Buildings and plants (5-40 years)		**9**		47
Accumulated depreciation		**(9)**		(50)
Diversified business property, net	**$**	**6**	$	8

Diversified business depreciation expense was $3 million, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PEC

Net diversified business property was $6 million at December 31, 2007 and $7 million at December 31, 2006. 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, 2007 and December 31, 2006. Diversified business depreciation expense was less than $1 million each in 2007, 2006 and 2005.

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 21B). Each of the Utilities' share of operating costs of the above jointly owned generating facilities is included within the corresponding line in the Statements of Income. The co-owner of Intercession City Unit 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:

2007 (in millions) Subsidiary	Facility	Company Ownership Interest		Plant Investment		Accumulated Depreciation		Construction Work in Progress
PEC	**Mayo**	**83.83%**	**$**	**519**	**$**	**270**	**$**	**128**
PEC	**Harris**	**83.83%**		**3,175**		**1,581**		**21**
PEC	**Brunswick**	**81.67%**		**1,647**		**959**		**16**
PEC	**Roxboro Unit 4**	**87.06%**		**634**		**164**		**39**
PEF	**Crystal River Unit 3**	**91.78%**		**817**		**450**		**177**
PEF	**Intercession City Unit P11**	**66.67%**		**23**		**9**		**–**

2006 (in millions) Subsidiary	Facility	Company Ownership Interest		Plant Investment		Accumulated Depreciation		Construction Work in Progress
PEC	Mayo	83.83%	$	517	$	263	$	–
PEC	Harris	83.83%		3,159		1,489		18
PEC	Brunswick	81.67%		1,632		941		15
PEC	Roxboro Unit 4	87.06%		356		163		1
PEF	Crystal River Unit 3	91.78%		811		452		76
PEF	Intercession City Unit P11	66.67%		23		7		–

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, 2007 and 2006, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $29 million and $30 million, respectively. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2007 and 2006 at PEF. At December 31, 2007 and 2006, additional PEF-related asset retirement costs, net of accumulated depreciation, of $121 million and $126 million, respectively, were recorded at Progress Energy as purchase accounting adjustments when we purchased Florida Progress Corporation (Florida Progress) in 2000. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $804 million and $735 million at December 31, 2007 and 2006, respectively, for PEC and $580 million and $552 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2007, 2006 and 2005. Management believes that nuclear 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 AROs, which are included in depreciation and amortization expense, were $96 million, $96 million and $90 million in 2007, 2006 and 2005, respectively, for PEC and $30 million, $27 million and $78 million in 2007, 2006 and 2005, respectively, for PEF.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant 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)	**2007**	2006	**2007**	2006	**2007**	2006
Removal costs	**$ 1,410**	$ 1,341	**$ 794**	$ 727	**$ 616**	$ 614
Nonirradiated decommissioning costs	**141**	137	**80**	76	**61**	61
Dismantlement costs	**125**	124	**–**	–	**125**	124
Non-ARO cost of removal	**$ 1,676**	$ 1,602	**$ 874**	$ 803	**$ 802**	$ 799

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 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (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 July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

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 22D). 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. We expect to submit an application requesting a 20-year extension of this license 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 $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 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. PEF's reserve for fossil plant dismantlement was approximately $146 million and $145 million at December 31, 2007 and 2006, 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 previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 1D).

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 our abandoned synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $1 million at December 31, 2006, and none at December 31, 2007.

The following table presents the changes to the AROs during the years ended December 31, 2007 and 2006. Revisions to prior estimates of the PEC regulated ARO are related to 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, 2006	$ 1,239	$ –	$ 949	$ 290
Accretion expense	72	–	57	15
Remediation	(2)	1	(2)	–
Revisions to prior estimates	(6)	–	–	(6)
Asset retirement obligations at December 31, 2006	1,303	1	1,004	299
Accretion expense	**75**	**–**	**59**	**16**
Remediation	**–**	**(1)**	**–**	**–**
Asset retirement obligations at December 31, 2007	**$ 1,378**	**$ –**	**$ 1,063**	**$ 315**

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 $1.750 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 $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $34 million with respect to the primary coverage, $37 million with respect to the decontamination, decommissioning and excess property coverage, and $24 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 $10.760 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 each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $100 million for each reactor owned for each incident. 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 per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 31, 2008.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion for non-certified acts, 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.

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

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 Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Trade accounts receivable	**$ 586**	$ 628	**$ 291**	$ 285	**$ 264**	$ 288
Unbilled accounts receivable	**220**	227	**156**	157	**59**	55
Notes receivable	**67**	57	–	–	–	–
Derivatives accounts receivable	**247**	–	–	–	**13**	–
Other receivables	**46**	46	**31**	36	**13**	5
Allowance for doubtful receivables	**(29)**	(28)	**(6)**	(5)	**(10)**	(8)
Total receivables	**$ 1,137**	$ 930	**$ 472**	$ 473	**$ 339**	$ 340

B. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Fuel for production	**$ 455**	$ 470	**$ 210**	$ 230	**$ 245**	$ 240
Inventory for sale	**–**	2	**–**	–	**–**	–
Materials and supplies	**520**	442	**284**	247	**236**	194
Emission allowances	**19**	22	**16**	20	**3**	2
Total inventory	**$ 994**	$ 936	**$ 510**	$ 497	**$ 484**	$ 436

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy of $65 million and $44 million at December 31, 2007 and 2006, respectively, and PEC of $44 million at December 31, 2007 and 2006.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $32 million, $3 million and $29 million, respectively, at December 31, 2007. Progress Energy, PEC and PEF did not have any long-term emission allowance amounts at December 31, 2006.

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 could 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, such an event 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)	**2007**	2006
Deferred fuel cost – current (Note 7B)	**$ 154**	$ 196
Deferred fuel cost – long-term (Note 7B)	**114**	114
Deferred impact of ARO – PEC (Note 1D)	**294**	282
Income taxes recoverable through future rates (Note 14)	**141**	114
Loss on reacquired debt (Note 1D)	**43**	46
Storm deferral (Notes 7B and 7C)	**22**	102
Postretirement benefits (Note 16)	**212**	373
Derivative mark-to-market adjustment (Note 17A)	**–**	78
Environmental (Notes 7B, 7C and 21A)	**40**	72
Investment in GridSouth (Note 7D)	**22**	–
Other	**43**	50
Total long-term regulatory assets	**931**	1,231
Deferred fuel cost – current (Note 7C)	**(154)**	(63)
Deferred energy conservation cost and other current regulatory liabilities	**(19)**	(13)
Total current regulatory liabilities	**(173)**	(76)
Non-ARO cost of removal (Note 5D)	**(1,676)**	(1,602)
Deferred impact of ARO – PEF (Note 1D)	**(226)**	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(351)**	(330)
Clean Smokestacks Act compliance (Note 7B)	**–**	(333)
Derivative mark-to-market adjustment (Note 17A)	**(185)**	–
Storm reserve (Note 7C)	**(63)**	(2)
Other	**(38)**	(55)
Total long-term regulatory liabilities	**(2,539)**	(2,543)
Net regulatory liabilities	**$ (1,627)**	$ (1,192)

PEC

(in millions)	2007	2006
Deferred fuel cost – current (Note 7B)	**$ 148**	$ 196
Deferred fuel cost – long-term (Note 7B)	**114**	114
Deferred impact of ARO (Note 1D)	**294**	282
Income taxes recoverable through future rates (Note 14)	**51**	50
Loss on reacquired debt (Note 1D)	**18**	19
Storm deferral (Note 7B)	**6**	12
Postretirement benefits (Note 16)	**126**	243
Environmental (Note 7B)	**10**	15
Investment in GridSouth (Note 7D)	**22**	–
Other	**38**	42
Total long-term regulatory assets	**679**	777
Non-ARO cost of removal (Note 5D)	**(874)**	(803)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(188)**	(171)
Derivative mark-to-market adjustment (Note 17A)	**(19)**	–
Clean Smokestacks Act compliance (Note 7B)	**–**	(333)
Other	**(16)**	(13)
Total long-term regulatory liabilities	**(1,097)**	(1,320)
Net regulatory liabilities	**$ (270)**	(347)

PEF

(in millions)	2007	2006
Deferred fuel cost – current (Note 7C)	**$ 6**	**$ –**
Storm deferral (Note 7C)	**16**	90
Income taxes recoverable through future rates (Note 14)	**90**	64
Loss on reacquired debt (Note 1D)	**25**	27
Postretirement benefits (Note 16)	**86**	130
Derivative mark-to-market adjustment (Note 17A)	**–**	78
Environmental (Notes 7C and 21A)	**30**	57
Other	**5**	8
Total long-term regulatory assets	**252**	454
Deferred fuel cost – current (Note 7C)	**(154)**	(63)
Deferred energy conservation cost and other current regulatory liabilities	**(19)**	(13)
Total current regulatory liabilities	**(173)**	(76)
Non-ARO cost of removal (Note 5D)	**(802)**	(799)
Deferred impact of ARO (Note 1D)	**(96)**	(88)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(163)**	(159)
Derivative mark-to-market adjustment (Note 17A)	**(166)**	–
Storm reserve (Note 7C)	**(63)**	(2)
Other	**(26)**	(43)
Total long-term regulatory liabilities	**(1,316)**	(1,091)
Net regulatory liabilities	**$ (1,231)**	$ (713)

Except for portions of deferred fuel costs and loss on reacquired debt, 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 anticipate recovering long-term deferred fuel costs in 2009 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

B. PEC RETAIL RATE MATTERS

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity (ROE) of 12.75 percent. In June 2002, the North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

During the rate freeze period, the legislation provided for a minimum amortization and recovery of 70 percent of the original estimated compliance costs of $813 million (or $569 million) while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. For the years ended December 31, 2007, 2006 and 2005, PEC recognized amortization of $34 million, $140 million and $147 million, respectively, and recognized $569 million in cumulative amortization through December 31, 2007.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

See Note 21B for additional information about the Clean Smokestacks Act.

FUEL COST RECOVERY

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $12 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kilowatt-hours (kWh), or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006;

$48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

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. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of 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. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize the respective jurisdictional portion of $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense. During the year ended December 31, 2007, PEC recorded $3 million of amortization expense. Additionally, PEC reduced the regulatory asset by $2 million during the year ended December 31, 2007, based on newly available data regarding certain remediation sites and insurance proceeds (See Note 21A).

The NCUC and SCPSC 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, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $37 million in 2007. No additional depreciation expense from accelerated cost recovery was recorded in 2006 or 2005. Through December 31, 2007, PEC recorded total accelerated depreciation of $440 million, of which $363 million was recorded for the North Carolina jurisdiction and $77 million was recorded for the South Carolina jurisdiction.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of new demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs that are intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs through December 31, 2007, for future recovery.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred an immaterial amount of implementation and program costs through December 31, 2007, for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy- efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

C. PEF RETAIL RATE MATTERS

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with 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 the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2007 threshold of $1.537 billion and thus no revenues were subject to revenue sharing. Both the 2007 base threshold of $1.537 billion and the 2007 cap of $1.588 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. PEF's 2006 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the 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. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) 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 as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. 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.

PASS-THROUGH CLAUSE COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased due to specified generation facilities placed in service in 2007 by $2.73 for the first 1,000 kWh effective January 1, 2008. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF's current regulatory liabilities totaled $173 million, which were comprised of over-recovered fuel and capacity costs of $140 million, accrued disallowed fuel costs of $14 million, over-recovered conservation costs of $14 million and over-recovered environmental compliance of $5 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices have been prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3, bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification. The petition filed with the FPSC included estimated project costs of approximately $382 million. These cost estimates may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, estimated at $6 million, through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost- recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

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 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 kWh 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 O&M expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, 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. In 2007, 2006 and 2005, PEF recorded amortization of $75 million, $122 million and $50 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which began August 2007, is expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified. Through December 31, 2007, PEF had recorded an additional $55 million of storm reserve from the extension of the storm surcharge. At December 31, 2007, PEF's storm reserve totaled $63 million.

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 October 29, 2007, PEF submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent. PEF received FERC approval of the settlement agreement on December 17, 2007. The new rates were effective January 1, 2008, and PEF estimates the impact of the new rates will increase 2008 revenues by $1 million to $2 million.

D. REGIONAL TRANSMISSION ORGANIZATIONS

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (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 Transco, LLC (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; no consensus was reached on creating a southeast RTO. 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.

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On

February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. Consequently, in December 2007, PEC recorded an $11 million charge to amortization expense to reduce the North Carolina portion of development costs, which is included in depreciation and amortization on the Consolidated Statements of Income. PEC's recorded investment in GridSouth totaled $22 million and $33 million at December 31, 2007 and 2006. PEC expects to recover its GridSouth development costs based on precedent regulatory proceedings; in 2007, PEC reclassified its investment in GridSouth from other assets and deferred debits to regulatory assets on the Consolidated Balance Sheets. We cannot predict the outcome of this matter.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

E. NUCLEAR LICENSE RENEWALS

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved. PEC anticipates a decision from the NRC in 2008. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF expects to submit an application requesting a 20-year extension of this license in the first quarter of 2009.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2007 and 2006; each test indicated no impairment.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. At December 31, 2007 and 2006, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. There were no changes to the assignment of the carrying amounts to PEC and PEF in 2007 or 2006.

Goodwill impairment tests were performed at our CCO-Georgia Operations reporting unit level, which was comprised of four nonregulated generating plants (Georgia Operations). As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed the annual goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3A).

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented the entirety of the synthetic fuels intangible assets; these assets had been reported within our former Coal and Synthetic Fuels segment (See Note 3B).

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 2006, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million, of which $64 million has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million in both 2006 and 2005.

A. LONG-LIVED ASSETS

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income, as discussed in Note 3B. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within our former Coal and Synthetic Fuels segment. There were no impairments of long-lived assets in 2007.

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 FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. There were no other-than-temporary impairments in 2007. 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 on a pre-tax basis in both 2006 and 2005.

10. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2007 and 2006, we had 500 million shares of common stock authorized under our charter, of which 260 million shares and 256 million shares, respectively, were outstanding. During 2007, 2006 and 2005, respectively, we issued approximately 3.4 million, 4.2 million and 4.8 million shares of common stock, resulting in approximately $151 million, $185 million and $208 million in proceeds. Included in these amounts for 2007, 2006 and 2005, respectively, were approximately 1.0 million, 1.6 million and 4.6 million shares for proceeds of approximately $46 million, $70 million and $199 million, to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2007 and 2006, we had approximately 50 million shares and 54 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 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. 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, 2007, there were no significant restrictions on the use of retained earnings (See Note 12).

PEC

At December 31, 2007 and 2006, 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, 2007, 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, 2007 and 2006, 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, 2007, 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. At December 31, 2007 and 2006, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. 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. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 1.7 million and 2.3 million ESOP suspense shares at December 31, 2007 and 2006, respectively, with a fair value of $82 million and $112 million, respectively. ESOP shares allocated to plan participants totaled 10.6 million and 10.9 million at December 31, 2007 and 2006, 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 $23 million, $14 million and $18 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $30 million, $23 million and $30 million for the years ended December 31, 2007, 2006 and 2005, 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.

Effective January 1, 2008, the 401(k) Plan was revised. As revised, the employer match percentage was increased and the employee stock incentive plan based on goal attainment was discontinued.

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $14 million, $8 million and $11 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $18 million, $13 million and $17 million for the years ended December 31, 2007, 2006 and 2005, 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, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $6 million, $4 million and $6 million for the years ended December 31, 2007, 2006 and 2005, respectively.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan (EIP) and 2002 EIP, 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. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. No stock options have been granted since 2004. 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, 2007, 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	4.0	$43.70
Canceled	–	45.55
Exercised	(2.3)	43.47
Options outstanding, December 31	1.7	43.99
Options exercisable, December 31	1.7	43.99

The options outstanding and exercisable at December 31, 2007, had a weighted-average remaining contractual life of 5.0 years and an aggregate intrinsic value of $8 million. Total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005, respectively, was $17 million, $10 million and less than $1 million.

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 grant date using a Black-Scholes option pricing model. 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.

As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2007. Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year. 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
Net income, as reported	$	697
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		2
Pro forma net income	$	695
Earnings per share		
Basic – as reported	$	2.82
Basic – pro forma		2.81
Diluted – as reported		2.82
Diluted – pro forma		2.81

Cash received from the exercise of stock options totaled $105 million, $115 million and $8 million, respectively, during the years ended December 31, 2007, 2006 and 2005. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2005, was not significant.

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore no compensation expense was recognized in 2007.

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.

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
Net income, as reported	$	493
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		2
Pro forma net income	$	491

PEF

Stock option expense totaling less than $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options were fully vested; therefore no compensation expense was recognized in 2007.

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.

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
Net income, as reported	$	260
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects		1
Pro forma net income	$	259

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. Our long-term compensation program currently includes two types of equity-based incentives: performance shares under the Performance Share Sub Plan (PSSP) and restricted stock programs. The compensation program was established pursuant to our 1997 EIP and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the 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, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both of which were based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. 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 subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities totaling $3 million, $4 million and $5 million were paid in the years ended December 31, 2007, 2006 and 2005, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2007, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares(a)	Weighted-Average Grant Date Fair Value
Beginning balance	1,044,583	$44.26
Granted	892,410	50.70
Paid(b)	(190,567)	50.70
Forfeited	(116,431)	44.84
Ending balance	1,629,995	$44.97

a) Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

b) Shares paid include only target shares as originally granted. Additional shares of 106,478 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.27 and $44.24, respectively.

The Restricted Stock Award (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, 2007, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	604,238	$43.82
Granted	7,000	49.54
Vested	(303,935)	44.08
Forfeited	(38,668)	43.16
Ending balance	268,635	$43.77

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of restricted stock granted was $44.51 and $42.56, respectively.

The total fair value of restricted stock awards vested during the years ended December 31, 2007, 2006 and 2005 was $13 million, $4 million and $7 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the years ended December 31, 2006 and 2005, respectively. Cash expended to purchase shares for 2007 was not significant due to the curtailment of the RSA program and the rollout of the new restricted stock unit (RSU) program.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers, and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. 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. RSUs are not included as shares outstanding in the basic earnings per share calculation until shares are no longer forfeitable. Units are converted to shares upon vesting. A summary of the status of nonvested RSUs at December 31, 2007, and changes during the year then ended, is presented below:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	–	$ –
Granted	913,282	50.33
Vested	(49,430)	50.70
Forfeited	(39,394)	50.70
Ending balance	824,458	$50.29

The total fair value of RSUs vested during the year ended December 31, 2007, was $3 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $70 million for the year ended December 31, 2007, with a recognized tax benefit of $27 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $25 million with a recognized tax benefit of $10 million and $10 million, with a recognized tax benefit of $4 million, for the years ended December 31, 2006 and 2005, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2007, there was $51 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 1.8 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $41 million for the year ended December 31, 2007, with a recognized tax benefit of $16 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $14 million with a recognized tax benefit of $6 million and $7 million, with a recognized tax benefit of $3 million, for the years ended December 31, 2006 and 2005, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

PEF's Statements of Income included total recognized expense for other stock-based compensation plans of $22 million for the year ended December 31, 2007, with a recognized tax benefit of $9 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2006, with a recognized tax benefit of $3 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $3 million for the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to other stock-based compensation plans was capitalized.

C.EARNINGS PER COMMON SHARE

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effects of the nonvested portion of restricted stock, restricted stock unit awards and performance share 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)	**2007**	2006	2005
Weighted-average common shares – basic	**256.1**	250.4	246.6
Net effect of dilutive stock-based compensation plans	**0.6**	0.4	0.4
Weighted-average shares – fully diluted	**256.7**	250.8	247.0

There were 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 1.8 million, 2.4 million and 3.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. There were 0.1 million, 1.8 million and 2.9 million stock options outstanding at December 31, 2007, 2006 and 2005, 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		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Loss on cash flow hedges	**$ (23)**	$ (14)	**$ (10)**	$ (5)	**$ (8)**	$ (1)
Pension and other postretirement benefits	**(13)**	(39)	**–**	–	**–**	–
Other	**2**	4	**–**	4	**–**	–
Total accumulated other comprehensive loss	**$ (34)**	$ (49)	**$ (10)**	$ (1)	**$ (8)**	$ (1)

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, 2007 and 2006, preferred stock outstanding consisted of the following:

	Shares		Redempti	
(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, 2007):

(in millions)		**2007**	2006
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	**$2,600**	$2,600
Unamortized fair value hedge gain, net		**–**	(1)
Unamortized premium and discount, net		**(3)**	(18)
Long-term debt, net		**2,597**	2,581
PEC			
First mortgage bonds, maturing 2009-2035	5.65%	**2,000**	2,200
Pollution control obligations, maturing 2017-2024	4.57%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	22
Unamortized premium and discount, net		**(8)**	(21)
Current portion of long-term debt		**(300)**	(200)
Long-term debt, net		**3,183**	3,470
PEF			
First mortgage bonds, maturing 2008-2037	5.64%	**2,380**	1,630
Pollution control obligations, maturing 2018-2027	4.32%	**241**	241
Senior unsecured notes, maturing 2008	5.27%	**450**	450
Medium-term notes, maturing 2008-2028	6.75%	**152**	241
Unamortized premium and discount, net		**(5)**	(5)
Current portion of long-term debt		**(532)**	(89)
Long-term debt, net		**2,686**	2,468
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(38)**	(38)
Long-term debt, net		**271**	271
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2008	6.46%	**45**	80
Current portion of long-term debt		**(45)**	(35)
Long-term debt, net		**–**	45
Progress Energy consolidated long-term debt, net		**$8,737**	$8,835

On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF’s utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

At December 31, 2007 and 2006, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2007 and 2006, we had no outstanding borrowings under our credit facilities. 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, 2007:

(in millions)	Description		Total		Outstanding		Reserved[a]		Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$	1,130	$	–	$	220	$	910
PEC	Five-year (expiring 6/28/10)		450		–		–		450
PEF	Five-year (expiring 3/28/10)		450		–		–		450
Total credit facilities		$	2,030	$	–	$	220	$	1,810

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. Fees and interest rates under Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's Investors Service, Inc. (Moody's) and BBB by S&P. Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P. Fees and interest rates under PEF's RCA are 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 following table summarizes our outstanding commercial paper and other short-term debt and related weighted-average interest rates at December 31, 2007:

(in millions)			
Progress Energy, Inc.	5.48%	$	201
PEC			–
PEF			–
Total	5.48%	$	201

We had no commercial paper outstanding or other short-term debt at December 31, 2006.

The following table presents the aggregate maturities of long-term debt at December 31, 2007:

(in millions)		Progress Energy Consolidated		PEC		PEF
2008	$	877	$	300	$	532
2009		400		400		–
2010		406		6		300
2011		1,000		–		300
2012		950		500		–
Thereafter		6,035		2,285		2,091
Total	$	9,668	$	3,491	$	3,223

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. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2007, 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%	54.4%
PEC	65%	48.8%
PEF	65%	53.2%

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

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 of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision can be triggered by 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 can only be triggered by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or 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 $2.6 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, so long as no shares of preferred stock are outstanding. At December 31, 2007, Progress Energy, Inc. had no shares of preferred stock outstanding.

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, 2007, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's 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, 2007, PEC's common stock equity was approximately 53.8 percent of total capitalization. At December 31, 2007, none of PEC's cash dividends or distributions on common stock was restricted.

PEF

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, 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, 2007, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, 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, exceeds 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. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's 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, 2007, PEF's common stock equity was approximately 52.5 percent of total capitalization. At December 31, 2007, none of PEF's cash dividends or distributions on common stock was restricted.

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, 2007, PEC and PEF had a total of $2.669 billion and $2.621 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 18 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 Note 17 for a discussion of risk management activities and derivative transactions.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. INVESTMENTS

At December 31, 2007 and 2006, 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)	**2007**	2006	**2007**	2006	**2007**	2006
Nuclear decommissioning trust (See Note 5D)	**$ 1,384**	$ 1,287	**$ 804**	$ 735	**$ 580**	$ 552
Investments in equity securities (a)	**–**	5	–	4	**–**	–
Equity method investments (b)	**23**	24	**11**	13	**2**	1
Cost investments (c)	**8**	8	**3**	2	**–**	–
Benefit investment trusts (d)	**82**	80	**2**	2	**–**	–
Company-owned life insurance (d)	**168**	161	**112**	99	**39**	39
Marketable debt securities (e)	**1**	71	**1**	50	–	–
Total	**$ 1,666**	$ 1,636	**$ 933**	$ 905	**$ 621**	$ 592

(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 miscellaneous other property and investments in the Consolidated Balance Sheets 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 20).

(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) We actively invest 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 we intend 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 $9.614 billion and $9.159 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.897 billion and $9.543 billion at December 31, 2007 and 2006, 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, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007

(in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$ 465**	**$ 354**	**$ 819**
Debt securities	**574**	**11**	**585**
Cash equivalents	**18**	**–**	**18**
Total	**$ 1,057**	**$ 365**	**$ 1,422**

2006

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$ 428	$ 324	$ 752
Debt securities	606	13	619
Cash equivalents	19	–	19
Total	$ 1,053	$ 337	$ 1,390

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 8
Due after one through five years	145
Due after five through 10 years	198
Due after 10 years	234
Total	$ 585

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)	**2007**	2006	2005
Proceeds	**$ 1,334**	$ 2,547	$ 3,755
Realized gains	**35**	33	26
Realized losses	**37**	24	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2007 and 2006 for investments in these trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2007 and 2006 our other securities had no investments in a continuous loss position for greater than 12 months.

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $3.483 billion and $3.670 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.545 billion and $3.732 billion at December 31, 2007 and 2006, 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 PEC 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 fund, PEC holds other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the PEC Consolidated Balance Sheets at amounts that approximate fair value. PEC's available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007

(in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$ 256**	**$ 191**	**$ 447**
Debt securities	**341**	**6**	**347**
Cash equivalents	**11**	**–**	**11**
Total	**$ 608**	**$ 197**	**$ 805**

2006

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$ 232	$ 170	$ 402
Debt securities	364	7	371
Cash equivalents	9	–	9
Total	$ 605	$ 177	$ 782

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 7
Due after one through five years	86
Due after five through 10 years	99
Due after 10 years	155
Total	$ 347

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)	**2007**	2006	2005
Proceeds	**$ 609**	$ 995	$ 1,678
Realized gains	**12**	21	13
Realized losses	**22**	14	16

Available-for-sale securities in PEC's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2007 and 2006 PEC's other securities had no investments in a continuous loss position for greater than 12 months.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $3.218 billion and $2.557 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.239 and $2.567 billion at December 31, 2007 and 2006, 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, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	**$ 209**	**$ 163**	**$ 372**
Debt securities	**193**	**5**	**198**
Cash equivalents	**7**	**–**	**7**
Total	**$ 409**	**$ 168**	**$ 577**

2006

(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$ 196	$ 154	$ 350
Debt securities	184	6	190
Cash equivalents	9	–	9
Total	$ 389	$ 160	$ 549

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 1
Due after one through five years	51
Due after five through 10 years	84
Due after 10 years	62
Total	$ 198

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)	**2007**	2006	2005
Proceeds	**$ 535**	$ 509	$ 330
Realized gains	**22**	12	13
Realized losses	**14**	9	13

Available-for-sale securities in PEF's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2007 and 2006 PEF's other securities had no investments in a loss position.

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. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

PROGRESS ENERGY

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

(in millions)	2007	2006
Deferred income tax assets		
Asset retirement obligation liability	**$ 146**	$ 141
Compensation accruals	**101**	86
Deferred revenue	–	28
Derivative instruments	–	42
Environmental remediation liability	**32**	36
Income taxes refundable through future rates	**317**	216
Investments	–	28
Pension and other postretirement benefits	**306**	364
Unbilled revenue	**41**	36
Other	**122**	103
Federal income tax credit carry forward	**836**	851
State net operating loss carry forward (net of federal expense)	**87**	54
Valuation allowance	**(79)**	(71)
Total deferred income tax assets	**1,909**	1,914
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,482)**	(1,379)
Deferred fuel recovery	**(64)**	(60)
Deferred storm costs	**(6)**	(51)
Derivative instruments	**(59)**	–
Income taxes recoverable through future rates	**(384)**	(436)
Investments	**(25)**	–
Prepaid pension costs	**(18)**	–
Other	**(50)**	(66)
Total deferred income tax liabilities	**(2,088)**	(1,992)
Total net deferred income tax liabilities	**$ (179)**	$ (78)

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

(in millions)	2007	2006
Current deferred income tax assets	$ 27	$ 142
Noncurrent deferred income tax assets, included in other assets and deferred debits	65	17
Current deferred income tax liabilities, included in other current liabilities	(5)	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(266)	(237)
Total net deferred income tax liabilities	$ (179)	$ (78)

At December 31, 2007, the federal income tax credit carry forward includes $772 million of alternative minimum tax credits that do not expire and $64 million of general business credits that will expire during the period 2020 through 2027.

At December 31, 2007, we had gross state net operating loss carry forwards of $1.9 billion that will expire during the period 2008 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $8 million during 2007. 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.

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

	2007	2006	2005
Effective income tax rate	32.3%	37.5%	36.1%
State income taxes, net of federal benefit	(2.8)	(3.5)	(3.5)
Investment tax credit amortization	1.1	1.3	1.6
Employee stock ownership plan dividends	1.1	1.3	1.5
Domestic manufacturing deduction	1.0	0.4	1.0
Other differences, net	2.3	(2.0)	(1.7)
Statutory federal income tax rate	35.0%	35.0%	35.0%

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

(in millions)	2007	2006	2005
Current – federal	$ 285	$ 394	$ 441
– state	36	70	74
Deferred – federal	13	(94)	(173)
– state	11	(17)	(31)
State net operating loss carry forward	1	(2)	–
Investment tax credit	(12)	(12)	(13)
Total income tax expense	$ 334	$ 339	$ 298

Total income tax expense 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 2007 or 2006.

- Taxes related to discontinued operations recorded net of tax for 2007, 2006 and 2005, which are presented separately in Notes 3A through 3H.

- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $2 million, which was recorded in common stock during 2005, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP.

In July 2006, the FASB issued FIN 48, which clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required for the application of FIN 48; recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority. We adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $2 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, our liability for unrecognized tax benefits at January 1, 2007, was $126 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $24 million would have affected the effective tax rate for income from continuing operations, if recognized. At December 31, 2007, our liability for unrecognized tax benefits decreased to $93 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations decreased to $10 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)		
Unrecognized tax benefits at January 1, 2007	**$**	**126**
Gross amounts of increases as a result of tax positions taken in a prior period		**32**
Gross amounts of decreases as a result of tax positions taken in a prior period		**(41)**
Gross amounts of increases as a result of tax positions taken in the current period		**22**
Gross amounts of decreases as a result of tax positions taken in the current period		**(32)**
Amounts of net decreases relating to settlements with taxing authorities		**(14)**
Reductions as a result of a lapse of the applicable statute of limitations		–
Unrecognized tax benefits at December 31, 2007	**$**	**93**

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

Prior to the adoption of FIN 48, we and the Utilities accounted for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2007, the interest expense related to unrecognized tax benefits was $1 million, net, of which a $15 million expense component was deferred as a regulatory asset by PEF and not recognized in our Consolidated Statement of Operations. During 2007 there were no penalties related to unrecognized tax benefits. As of January 1, 2007, we had accrued $24 million for interest and penalties. As of December 31, 2007, we have accrued $23 million for interest and penalties, which are included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

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

(in millions)	**2007**	2006
Deferred income tax assets:		
Asset retirement obligation liability	**$ 140**	$ 132
Compensation accruals	**55**	47
Deferred revenue	**–**	28
Income taxes refundable through future rates	**82**	68
Pension and other postretirement benefits	**166**	200
Other	**40**	37
Federal income tax credit carry forward	**1**	1
Total deferred income tax assets	**484**	513
Deferred income tax liabilities:		
Accumulated depreciation and property cost differences	**(1,013)**	(930)
Deferred fuel recovery	**(60)**	(55)
Income taxes recoverable through future rates	**(291)**	(317)
Other	**(7)**	(37)
Total deferred income tax liabilities	**(1,371)**	(1,339)
Total net deferred income tax liabilities	**$ (887)**	$ (826)

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

(in millions)	**2007**	2006
Current deferred income tax assets, included in prepayments and other current assets	**$ 8**	$ 34
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(895)**	(860)
Total net deferred income tax liabilities	**$ (887)**	$ (826)

At December 31, 2007, the federal income tax credit carry forward includes $1 million of general business credits that will expire in 2020.

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

	2007	2006	2005
Effective income tax rate	**37.1%**	36.7%	32.7%
State income taxes, net of federal benefit	**(2.3)**	(2.3)	(2.1)
Investment tax credit amortization	**0.7**	0.8	1.1
Domestic manufacturing deduction	**1.1**	0.6	0.7
Progress Energy tax benefit allocation	–	–	2.9
Other differences, net	**(1.6)**	(0.8)	(0.3)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2007**	2006	2005
Current – federal	**$ 235**	$ 285	$ 343
– state	**19**	39	45
Deferred – federal	**34**	(42)	(120)
– state	**13**	(11)	(21)
Investment tax credit	**(6)**	(6)	(8)
Total income tax expense	**$ 295**	$ 265	$ 239

Total income tax expense 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 2007 or 2006.

- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $3 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $1 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $1 million, which was recorded in common stock during 2005, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP.

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 $27 million and $51 million at December 31, 2007 and 2006, respectively.

PEC adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $6 million reduction of the January 1, 2007, balance of retained earnings. Including the cumulative effect impact, PEC's liability for unrecognized tax benefits at January 1, 2007, was $43 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $9 million would have affected the effective tax rate, if recognized. At December 31, 2007, PEC's liability for unrecognized tax benefits decreased to $41 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $9 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)		
Unrecognized tax benefits at January 1, 2007	$	**43**
Gross amounts of increases as a result of tax positions taken in a prior period		**3**
Gross amounts of decreases as a result of tax positions taken in a prior period		**(15)**
Gross amounts of increases as a result of tax positions taken in the current period		**22**
Gross amounts of decreases as a result of tax positions taken in the current period		**(5)**
Amounts of decreases relating to settlements with taxing authorities		**(7)**
Reductions as a result of a lapse of the applicable statute of limitations		–
Unrecognized tax benefits at December 31, 2007	**$**	**41**

At December 31, 2006 and 2005, PEC had recorded $49 million and $92 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

At December 31, 2006 and 2005, PEC had recorded $5 million and $2 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. PEC's open federal tax years are from 2004 forward and PEC's open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEC cannot predict when those examinations will be completed. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the twelve-month period ending December 31, 2008.

PEC includes interest expense related to unrecognized tax benefits in interest charges and includes penalties in other, net on the Consolidated Statements of Income. During 2007, the interest expense and penalties related to uncertain tax benefits was $4 million and $0 respectively. As of January 1, 2007, PEC had accrued $4 million for interest and penalties. At December 31, 2007, PEC had accrued $8 million for interest and penalties, which is included in other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

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

(in millions)		2007		2006
Deferred income tax assets				
Compensation accruals	**$**	**21**	$	15
Derivative instruments		**–**		30
Environmental remediation liability		**18**		24
Income taxes refundable through future rates		**184**		95
Pension and other postretirement benefits		**142**		150
Reserve for storm damage		**25**		2
Unbilled revenue		**41**		36
Other		**56**		53
Total deferred income tax assets		**487**		405
Deferred income tax liabilities				
Accumulated depreciation and property cost differences		**(451)**		(429)
Deferred storm costs		**(6)**		(45)
Derivative instruments		**(64)**		–
Income taxes recoverable through future rates		**(93)**		(119)
Investments		**(63)**		(61)
Prepaid pension costs		**(86)**		(67)
Other		**(31)**		(38)
Total deferred income tax liabilities		**(794)**		(759)
Total net deferred income tax liabilities	**$**	**(307)**	$	(354)

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

(in millions)		2007		2006
Current deferred income tax assets	**$**	**39**	$	86
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities		**(346)**		(440)
Total net deferred income tax liabilities	**$**	**(307)**	$	(354)

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

	2007	2006	2005
Effective income tax rate	**31.2%**	37.0%	31.8%
State income taxes, net of federal benefit	**(3.3)**	(3.6)	(3.3)
Investment tax credit amortization	**1.3**	1.2	1.4
Domestic manufacturing deduction	**0.8**	0.3	0.9
Progress Energy tax benefit allocation	**–**	–	3.2
AFUDC equity	**2.6**	0.7	0.7
Other differences, net	**2.4**	(0.6)	0.3
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)		2007		2006		2005
Current – federal	**$**	**160**	$	207	$	146
– state		**28**		34		25
Deferred – federal		**(33)**		(36)		(39)
– state		**(5)**		(6)		(6)
Investment tax credit		**(6)**		(6)		(5)
Total income tax expense	**$**	**144**	$	193	$	121

Total income tax expense 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 2007 or 2006.

- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, which are presented separately in the Statements of Comprehensive Income.

- Less than $1 million of current tax benefit, which was recorded in common stock during 2007, 2006 and 2005, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D). PEF's intercompany tax receivable was approximately $41 million and $47 million at December 31, 2007 and 2006, respectively.

PEF adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a less than $1 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, PEF's liability for unrecognized tax benefits at January 1, 2007, was $72 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $4 million would have affected the effective tax rate, if recognized. At December 31, 2007, PEF's liability for unrecognized tax benefits decreased to $55 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate decreased to $3 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)		
Unrecognized tax benefits at January 1, 2007	**$**	**72**
Gross amounts of increases as a result of tax positions taken in a prior period		**23**
Gross amounts of decreases as a result of tax positions taken in a prior period		**(4)**
Gross amounts of increases as a result of tax positions taken in the current period		**2**
Gross amounts of decreases as a result of tax positions taken in the current period		**(25)**
Amounts of decreases relating to settlements with taxing authorities		**(13)**
Reductions as a result of a lapse of the applicable statute of limitations		**–**
Unrecognized tax benefits at December 31, 2007	**$**	**55**

At December 31, 2006 and 2005, PEF had recorded $26 million and $17 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Balance Sheets.

At December 31, 2006 and 2005, respectively, PEF had recorded $5 million and $7 million of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

We file consolidated federal and state income tax returns that include PEF. During 2007, we closed federal tax years 1998 to 2003. PEF's open federal tax years are from 2004 forward and PEF's open state tax years are generally from 1998 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEF cannot predict when those examinations will be completed. PEF is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the twelve-month period ending December 31, 2008.

Pursuant to a regulatory order, PEF records interest expense related to unrecognized tax benefits as a regulatory asset, which is amortized over a three-year period, with the amortization included in interest charges on the Statements of Income. Penalties are included in other, net on the Statements of Income. During 2007, the interest expense recorded as a regulatory asset was $15 million and penalties related to unrecognized tax benefits was $0. At January 1, 2007, PEF had accrued $7 million for interest and penalties. At December 31, 2007, PEF had accrued $18 million for interest and penalties, which is included in other liabilities and deferred credits on the Balance Sheets.

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 Earthco synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. We will make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. Monies held in the trust are generally not payable to the CVO holders until the completion of income tax audits. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payment held in trust for 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2007.

16. BENEFIT PLANS

A.POSTRETIREMENT BENEFITS

We have noncontributory defined benefit retirement plans for substantially all full-time employees that provide 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 the 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)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$ 46**	$ 45	$ 47	**$ 7**	$ 9	$ 9
Interest cost	**123**	117	117	**32**	33	33
Expected return on plan assets	**(155)**	(148)	(147)	**(6)**	(6)	(5)
Amortization of actuarial loss(a)	**15**	18	21	**2**	4	6
Other amortization, net (a)	**2**	–	–	**5**	5	5
Net periodic cost	**$ 31**	$ 32	$ 38	**$ 40**	$ 45	$ 48

(a) Adjusted to reflect PEF's rate treatment (See Note 16B).

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

We and the Utilities adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)," (SFAS No. 158) as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $78 million and $(41) million, respectively. No amounts related to our OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. The table below provides a summary of amounts recognized in other comprehensive income for 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF. Refer to the PEC and PEF sections below for more information with regard to these regulatory assets.

(in millions)	Pension Benefits	Other Postretirement Benefits
Other comprehensive income (loss)		
Recognized for the year		
Net actuarial gain	$ 24	$ 16
Other, net	(1)	–
Reclassification adjustments		
Net actuarial loss	2	–
Other, net	1	
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	66	82
Other, net	(8)	–
Amortized to income		
Net actuarial loss	13	2
Other, net	1	4

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$ 23**	$ 22	$ 22	**$ 5**	$ 4	$ 4
Interest cost	**56**	52	53	**15**	17	17
Expected return on plan assets	**(60)**	(59)	(62)	**(4)**	(4)	(4)
Amortization of actuarial loss	**12**	11	10	**–**	2	5
Other amortization, net	**2**	1	1	**1**	1	1
Net periodic cost	**$ 33**	$ 27	$ 24	**$ 17**	$ 20	$ 23

In addition to the net periodic cost reflected above, in 2005, PEC recorded costs for special termination benefits related to a voluntary enhanced retirement program of $21 million for pension benefits and $8 million for other postretirement benefits.

No amounts related to PEC's OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. Pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $59 million and $(19) million, respectively. In conjunction with the implementation of SFAS No. 158, amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The table below provides a summary of amounts recognized in regulatory assets for 2007 and amounts amortized from regulatory assets to net income for 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	$ 26	$ 82
Other, net	(6)	–
Amortized to net income		
Net actuarial loss	12	–
Other, net	2	1

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$ 16**	$ 16	$ 16	**$ 2**	$ 3	$ 3
Interest cost	**52**	49	48	**14**	14	13
Expected return on plan assets	**(84)**	(78)	(73)	**(1)**	(1)	(1)
Amortization of actuarial loss	**1**	3	8	**2**	1	2
Other amortization, net	**(1)**	(1)	(1)	**3**	4	4
Net periodic (benefit) cost	**$ (16)**	$ (11)	$ (2)	**$ 20**	$ 21	$ 21

In addition to the net periodic cost and benefit reflected above, in 2005 PEF recorded costs for special termination benefits related to a voluntary enhanced retirement program of $84 million for pension benefits and $7 million for other postretirement benefits.

No amounts related to PEF's OPEB or pension plans were recorded as a component of OCI for the years ended December 31, 2007, 2006 and 2005. Amounts that would otherwise be recorded in OCI are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process. The table below provides a summary of amounts recognized in regulatory assets for 2007 and amounts amortized from regulatory assets to net income for 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	$ 40	$ –
Other, net	(1)	–
Amortized to net income		
Net actuarial loss	1	2
Other, net	(1)	3

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

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**5.95%**	5.65%	5.70%	**5.95%**	5.65%	5.70%
Rate of increase in future compensation						
Bargaining	**4.25%**	3.50%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on						
plan assets	**9.00%**	9.00%	9.00%	**7.70%**	8.30%	8.25%

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 OPEB plan assets was 9.00% for PEC and 5.00% for PEF, 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 used an expected long-term rate of 9.0%, the low end of the range, for 2007, 2006 and 2005.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

SFAS No. 158 requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2007 and 2006 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$ 2,123**	$ 2,164	**$ 628**	$ 650
Service cost	**46**	45	**7**	9
Interest cost	**123**	117	**32**	33
Benefit payments	**(131)**	(174)	**(30)**	(29)
Plan amendment	**8**	18	**–**	(4)
Actuarial gain	**(27)**	(47)	**(96)**	(31)
Obligation at December 31	**2,142**	2,123	**541**	628
Fair value of plan assets at December 31	**1,996**	1,836	**75**	74
Funded status	**$ (146)**	$ (287)	**$ (466)**	$ (554)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $463 million and $2.123 billion at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $422 million and $2.083 billion at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $1.836 billion at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $2.100 billion and $2.083 billion at December 31, 2007 and 2006, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$ 48**	$ –	**$ –**	$ –
Current liabilities	**(10)**	(14)	**–**	(1)
Noncurrent liabilities	**(184)**	(273)	**(466)**	(553)
Funded status	**$ (146)**	$ (287)	**$ (466)**	$ (554)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$ 22**	$ 49	**$ (9)**	$ 7
Other, net	**6**	5	**1**	1
Recognized in regulatory assets, net				
Net actuarial loss	**136**	215	**25**	108
Other, net	**28**	22	**23**	28
Total not yet recognized as a component of net periodic cost(a)	**$ 192**	$ 291	**$ 40**	$ 144

(a) All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2008.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss (a)	**$ 7**	**$ 1**
Amortization of other, net(a)	**2**	**5**

(a) Adjusted to reflect PEF's rate treatment (See Note 16B).

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$ 952**	$ 969	**$ 330**	$ 333
Service cost	**23**	22	**5**	4
Interest cost	**56**	52	**15**	17
Plan amendment	**6**	9	**–**	–
Benefit payments	**(60)**	(83)	**(12)**	(11)
Actuarial (gain) loss	**3**	(17)	**(81)**	(13)
Obligation at December 31	**980**	952	**257**	330
Fair value of plan assets at December 31	**805**	741	**44**	45
Funded status	**$ (175)**	$ (211)	**$ (213)**	$ (285)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $980 million and $952 million at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $974 million and $946 million at December 31, 2007 and 2006, respectively, and plan assets of $805 million and $741 million at December 31, 2007 and 2006, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Current liabilities	**$ (2)**	$ (2)	**$ –**	$ –
Noncurrent liabilities	**(173)**	(209)	**(213)**	(285)
Funded status	**$ (175)**	$ (211)	**$ (213)**	$ (285)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Recognized in regulatory assets				
Net actuarial loss (gain)	**$ 104**	$ 142	**$ (12)**	$ 69
Other, net	**29**	25	**5**	7
Total not yet recognized as a component of net periodic cost	**$ 133**	$ 167	**$ (7)**	$ 76

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2008.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$ 5**	$ –
Amortization of other, net	**2**	**1**

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$ 880**	$ 896	**$ 246**	$ 259
Service cost	**16**	16	**2**	3
Interest cost	**52**	49	**14**	14
Plan amendment	**1**	8	**–**	(4)
Benefit payments	**(57)**	(69)	**(16)**	(17)
Actuarial gain	**(11)**	(20)	**(1)**	(9)
Obligation at December 31	**881**	880	**245**	246
Fair value of plan assets at December 31	**1,026**	952	**26**	24
Funded status	**$ 145**	$ 72	**$ (219)**	$ (222)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $345 million and $342 million at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $313 million and $311 million at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $240 million at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $849 million December 31, 2007 and 2006.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$ 221**	$ 174	$ –	$ –
Current liabilities	**(3)**	(3)	–	–
Noncurrent liabilities	**(73)**	(99)	**(219)**	(222)
Funded status	**$ 145**	$ 72	**$ (219)**	$ (222)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Recognized in regulatory assets, net				
Net actuarial loss	**$ 32**	$ 72	**$ 37**	$ 39
Other, net	**(1)**	(2)	**18**	21
Total not yet recognized as a component of net periodic cost	**$ 31**	$ 70	**$ 55**	$ 60

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2008.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$ –**	**$ 1**
Amortization of other, net	**(1)**	**4**

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

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Discount rate	**6.20%**	5.95%	**6.20%**	5.95%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	–	–
Supplementary plans	**5.25%**	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	**9.00%**	9.00%
Ultimate medical cost trend rate	–	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	–	–	**2015**	2014

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable. The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

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	$ 2	$ 1	$ 1
Effect on postretirement benefit obligation	31	15	14
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(26)	(12)	(12)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2007 include contributions directly to pension plan assets of $63 million, $33 million and $15 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 30 percent for PEC and 15 percent for PEF. The OPEB benefits payments are also reduced by prescription drug-related federal subsidies received. In 2007, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF. In 2006, the subsidies totaled $2 million for us, $1 million for PEC and $1 million for PEF.

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

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$ 1,836**	$ 1,770	**$ 74**	$ 76
Actual return on plan assets	**219**	222	**7**	8
Benefit payments	**(131)**	(174)	**(30)**	(29)
Employer contributions	**72**	18	**24**	19
Fair value of plan assets at December 31	**$ 1,996**	$ 1,836	**$ 75**	$ 74

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$ 741**	$ 731	**$ 45**	$ 49
Actual return on plan assets	**89**	91	**5**	6
Benefit payments	**(60)**	(83)	**(12)**	(11)
Employer contributions	**35**	2	**6**	1
Fair value of plan assets at December 31	**$ 805**	$ 741	**$ 44**	$ 45

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$ 952**	$ 895	**$ 24**	$ 22
Actual return on plan assets	**113**	114	**1**	1
Benefit payments	**(57)**	(69)	**(16)**	(17)
Employer contributions	**18**	12	**17**	18
Fair value of plan assets at December 31	**$ 1,026**	$ 952	**$ 26**	$ 24

The asset allocation for the benefit plans at the end of 2007 and 2006 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	2008	**2007**	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	25%	**28%**	30%
Equity – international	10%	**16%**	15%
Debt – domestic	50%	**41%**	40%
Debt – international	5%	**8%**	7%
Other	10%	**7%**	8%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
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 2008, we expect to make $34 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $149, $153, $155, $157, $164 and $877, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $37, $40, $43, $45, $47 and $247, 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 and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $3, $3, $4, $4, $5 and $39, respectively.

In 2008, PEC expects to make $24 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $73, $76, $78, $78, $81 and $426, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $16, $17, $19, $20, $22, and $121, 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 and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $1, $2, $2, $2, $2 and $17, respectively.

In 2008, PEF does not expect to make contributions directly to pension plan assets and expects to make $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $56, $57, $58, $59, $61 and $334, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $19, $20, $21, $22, $22 and $108, 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 and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $2, $2, $2, $2, $2 and $14, 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. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. 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.

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At

December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

In 2003, 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 20). At December 31, 2007 and 2006, the remaining liability was $10 million and $14 million, respectively.

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of the Georgia Contracts, forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled, and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil 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.

The Utilities have derivative instruments related to their 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 on the Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our or the Utilities' results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

PEC designates 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 power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. PEF did not have any commodity derivative instruments designated as cash flow hedges at December 31, 2007 and 2006. At December 31, 2007 and 2006, we and PEC did not have material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2007, 2006 and 2005.

At December 31, 2007 and 2006, the amount recorded in our or PEC's accumulated other comprehensive income related to commodity cash flow hedges was not material. PEF had no amount recorded in accumulated other comprehensive income related to commodity cash flow hedges at December 31, 2007 or 2006.

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

CASH FLOW HEDGES

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

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Fair value of liabilities	**$ (12)**	$ (2)	**$ (12)**	$ (1)	**$ –**	$ (1)

Gains and losses from cash flow hedges are recorded in accumulated other comprehensive income and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in accumulated other comprehensive income 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 2007, 2006 and 2005.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2007:

(term in years/millions of dollars)	Progress Energy	PEC	PEF
Maximum term	Less than 1	Less than 1	–
Accumulated other comprehensive loss, net of tax(a)	$ (24)	$ (12)	$ (8)
Portion expected to be reclassified to earnings during the next 12 months(b)	$ (2)	$ (1)	$ (1)

(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, 2006, including amounts related to terminated hedges, we had $14 million of after-tax deferred losses, including $5 million of after-tax deferred losses at PEC and $1 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

At December 31, 2007 and 2006, PEC had $200 million notional and $50 million notional, respectively, of interest rate cash flow hedges. During 2007, PEC entered into a combined $150 million notional of forward starting swaps and amended its $50 million notional 10-year forward starting swap in order to move the maturity date from October 1, 2017 to April 1, 2018, which now requires mandatory cash settlement on April 1, 2008.

In 2007, PEF entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. At December 31, 2006, PEF had $50 million notional of interest rate cash flow hedges. All of PEF's forward starting swaps were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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, 2007, we had no open interest rate fair value hedges. At December 31, 2006, we had $50 million notional of interest rate fair value hedges. At December 31, 2007 and 2006, the Utilities had no open interest rate fair value hedges.

18. 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, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2007, the Parent had issued $433 million 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 23). 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 PUHCA 1935. The repeal of PUHCA 1935 effective February 8, 2006, and subsequent regulation by the FERC did not 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 2007, 2006 and 2005 to PEC amounted to $182 million, $188 million and $202 million, respectively, and services provided to PEF were $174 million, $165 million and $169 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2007, 2006 and 2005 amounted to $54 million, $34 million and $54 million, respectively. Services provided by PEF to PEC during 2007, 2006 and 2005 amounted to $10 million, $8 million and $14 million, respectively.

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 5.49%, 5.17% and 3.77% at December 31, 2007, 2006 and 2005, 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.

Progress Fuels sold coal to PEF at cost in 2007 and 2006 and for an insignificant profit in 2005. 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, if any, of $2 million, $321 million and $402 million for the years ended December 31, 2007, 2006 and 2005, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

PEC and its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 14).

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable 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. These electric operations also distribute and sell electricity to other utilities, primarily in the eastern United States.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements of SFAS No. 131, “Disclosures about Segments of an Enterprise and Related Information,” as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties and coal terminal services. In 2007, we reclassified the operations of our synthetic fuels businesses and coal terminal services as discontinued operations (See Note 3B). For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005. Postretirement and severance charges reclassified to discontinued operations are not included in the table below.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the former Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the former Coal and Synthetic Fuels 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 2007, 2006 and 2005 were not significant. Prior to 2006, 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 1935, the Parent stopped 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. Operational results and assets to be divested are not included in the table presented below.

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$ 4,385	$ 4,748	$ 20	$ –	$ 9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation and amortization	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,962	10,004	16,383	(12,115)	26,234
Capital and investment expenditures	941	1,262	3	(2)	2,204

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$ 4,086	$ 4,638	$ –	$ –	$ 8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation and amortization	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	12,020	8,593	15,421	(11,293)	24,741
Capital and investment expenditures	808	741	12	(9)	1,552

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2005					
Revenues					
Unaffiliated	$ 3,991	$ 3,955	$ 2	$ –	$ 7,948
Intersegment	–	–	839	(839)	–
Total revenues	3,991	3,955	841	(839)	7,948
Depreciation and amortization	561	334	31	–	926
Interest income	8	1	94	(90)	13
Total interest charges, net	192	126	342	(85)	575
Postretirement and severance charges	55	102	1	–	158
Income tax expense (benefit)	239	121	(62)	–	298
Segment profit (loss)	490	258	(225)	–	523
Total assets	11,502	8,318	18,278	(13,673)	24,425
Capital and investment expenditures	682	543	19	(19)	1,225

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income 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)	2007	2006	2005
Other income			
Nonregulated energy and delivery services income	**$ 36**	$ 41	$ 32
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Contingent value obligation unrealized gain (Note 15)	**2**	–	6
Gain on sale of Level 3 stock (a)	**–**	32	–
Investment gains	**9**	4	4
Income from equity investments	**2**	1	1
AFUDC equity	**51**	21	16
Reversal of indemnification liability (Note 21B)	**–**	29	–
Other	**15**	13	16
Total other income	**119**	146	82
Other expense			
Nonregulated energy and delivery services expenses	**24**	27	23
Donations	**22**	20	18
Contingent value obligation unrealized loss (Note 15)	**4**	25	–
Investment losses	**4**	–	1
Loss from equity investments	**5**	3	7
Loss on debt redemption(b)	**–**	59	–
FERC audit settlement	**–**	–	7
Indemnification liability (Note 21B)	**–**	13	16
Other	**16**	15	11
Total other expense	**75**	162	83
Other, net – Progress Energy	**$ 44**	$ (16)	$ (1)

PEC

(in millions)	2007	2006	2005
Other income			
Nonregulated energy and delivery services income	**$ 14**	$ 15	$ 12
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Investment gains	**4**	–	–
Income from equity investments	**1**	–	1
AFUDC equity	**10**	4	3
Reversal of indemnification liability (Note 21B)	**–**	29	–
Other	**11**	10	9
Total other income	**44**	63	32
Other expense			
Nonregulated energy and delivery services expenses	**8**	7	9
Donations	**9**	10	8
Investment losses	**3**	–	–
Losses from equity investments	**1**	1	–
FERC audit settlement	**–**	–	4
Indemnification liability (Note 21B)	**–**	13	16
Other	**7**	7	10
Total other expense	**28**	38	47

Other, net – PEC	**$ 16**	$ 25	$ (15)

PEF

(in millions)		**2007**		2006		2005
Other income						
Nonregulated energy and delivery services income	**$**	**24**	$	26	$	20
Investment gains		**2**		2		2
AFUDC equity		**41**		17		13
Other		**1**		1		–
Total other income		**68**		46		35
Other expense						
Nonregulated energy and delivery services expenses		**16**		20		14
Donations		**8**		10		10
Losses from equity investments		**1**		1		–
FERC audit settlement		**–**		–		3
Other		**4**		2		1
Total other expense		**29**		33		28
Other, net – PEF	**$**	**39**	$	13	$	7

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3E). These gains are prior to the consideration of minority interest.

(b) On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

21. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. 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 frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. HAZARDOUS AND SOLID WASTE

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States 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, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various 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 PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

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.

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	**2007**	2006
PEC		
MGP and other sites[a]	**$ 16**	$ 22
PEF		
Remediation of distribution and substation transformers	**31**	43
MGP and other sites	**17**	18
Total PEF environmental remediation accruals[b]	**48**	61
Progress Energy nonregulated operations	**–**	3
Total Progress Energy environmental remediation accruals	**$ 64**	$ 86

(a) Expected to be paid out over one to five years.

(b) Expected to be paid out over one to fifteen years.

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. At December 31, 2006, the remaining accrual balance was approximately $3 million. For the year ended December 31, 2007, the accrual was reduced by approximately $3 million due to a reduction in the anticipated scope of work based on responses from regulatory agencies. Expenditures related to this liability were not material during 2007 and 2006.

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 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2007, including the Carolina Transformer site, the Ward Transformer site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses, net of insurance proceeds (See Note 7B).

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

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 the EPA's past expenditures in addressing conditions at the site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced PEC's allocable share, and the estimated scope of work increased. These factors resulted in a net reduction to PEC's accrual for this site. At December 31, 2007, PEC's recorded liability for the site was approximately $6 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

The EPA has also proposed, but not yet selected, a final remedial action plan to address stream segments downstream from the Ward Transformer site. The outcome of this matter cannot be predicted.

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 in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $33 million. During the year ended December 31, 2007, a settlement was reached between the PRPs and the EPA, and PEC recorded and paid an immaterial amount for its share of the settlement.

PEF

PEF has received approval from the FPSC for recovery of the majority 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, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

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. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our or PEF's results of operations or financial condition.

B. AIR AND WATER QUALITY

We are subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations include the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call), the Clean Smokestacks Act and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule (CAMR)). At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.567 billion, including $1.244 billion at PEC and $323 million at PEF. At December 31, 2006, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $932 million, including $904 million at PEC and $28 million at PEF.

As discussed in Note 7A, 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. Two of PEC’s largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2007, and 2006, the amount of the liability was $30 million and $29 million, respectively, based upon the respective current estimates for Clean Smokestacks Act compliance. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner’s share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC’s compliance with the Clean Smokestacks Act. In 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and accordingly, recorded the indemnification expense to Clean Smokestacks Act amortization. In a settlement agreement provisionally approved by the NCUC on December 20, 2007, eligible compliance costs in excess of the joint owner’s share will be treated in the same manner as PEC’s Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs, as ultimately approved by the NCUC (See Note 7A).

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

At December 31, 2007, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$ 2,018	$ 1,745	$ 1,202	$ 1,001	$ 675	$ 5,103
Purchased power	455	422	409	443	415	3,756
Construction obligations	714	211	42	–	–	–
Other purchase obligations	94	39	32	16	16	64
Total	$ 3,281	$ 2,417	$ 1,685	$ 1,460	$ 1,106	$ 8,923

PEC

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$ 958	$ 761	$ 664	$ 487	$ 308	$ 976
Purchased power	85	87	69	80	63	540
Construction obligations	84	22	–	–	–	–
Other purchase obligations	26	12	7	4	3	13
Total	$ 1,153	$ 882	$ 740	$ 571	$ 374	$ 1,529

PEF

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$ 1,060	$ 984	$ 538	$ 514	$ 367	$ 4,127
Purchased power	370	335	340	363	352	3,216
Construction obligations	630	189	42	–	–	–
Other purchase obligations	56	20	19	12	12	50
Total	$ 2,116	$ 1,528	$ 939	$ 889	$ 731	$ 7,393

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 $2.360 billion, $1.628 billion and $1.470 billion for 2007, 2006 and 2005, respectively. PEC's total payments under these commitments for its generating plants were $1.049 billion, $1.051 billion and $964 million in 2007, 2006 and 2005, respectively. PEF's payments totaled $1.311 billion, $577 million and $506 million in 2007, 2006 and 2005, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2008 to 2030. These purchased power contracts generally provide for capacity and energy payments.

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 $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $77 million, $80 million and $71 million for 2007, 2006 and 2005, 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 $39 million, $40 million and $44 million in 2007, 2006 and 2005, respectively.

In 2007, PEC executed a long-term agreement for the purchase of power from Southern Power Company. The agreement provides for capacity purchases of 305 MW for 2010, 310 MW for 2011 and 150 MW annually thereafter through 2019. Estimated payments for capacity and energy under the agreement are $22 million for 2010, $33 million for 2011 and $14 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs for approximately 195 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 $95 million, $182 million and $112 million in 2007, 2006 and 2005, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $161 million, $162 million and $175 million for 2007, 2006 and 2005, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million annually through 2011, $50 million for 2012 and $32 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 965 MW of capacity with expiration dates ranging from 2008 to 2030. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs 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, except one for 75 MW, have been approved by the FPSC. Total capacity purchases under these contracts amounted to $288 million, $277 million and $262 million for 2007, 2006 and 2005, respectively. At December 31, 2007, minimum expected future capacity payments under these contracts were $297 million, $263 million, $267 million, $281 million and $292 million for 2008 through 2012, respectively, and $3.053 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.

In January 2006, PEF entered into a conditional contract with Gulfstream Natural 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 January 1, 2031. The total cost to PEF associated with this agreement is approximately $777 million. 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 conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2006, PEF entered into a conditional contract with Devon Gas Services for the supply of natural gas to augment PEF's gas supply needs for the period from May to September for the years 2008 through 2011. The total cost to PEF associated with this agreement is approximately $251 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc. for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $1.026 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million. The transaction is subject to several conditions precedent, including FPSC approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through March 31, 2013. The total cost to PEF associated with this agreement is approximately $146 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In January and February 2007, PEF entered into conditional contracts with Chevron Natural Gas for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, to May 31, 2013. The total cost to PEF associated with these agreements is approximately $935 million. The transactions are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of these agreements the estimated costs associated with these agreements 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 $675 million, $365 million and $91 million for 2007, 2006 and 2005, respectively. PEC's future obligations related to Clean Smokestacks Act capital projects are $84 million for 2008 and $22 million for 2009. Total payments under PEC's contracts related to Clean Smokestacks Act projects were $208 million and $225 million for 2007 and 2006, respectively. PEC did not have any payments related to construction obligations in 2005. PEF has purchase obligations related to various capital projects related to new generation and Florida CAIR. Total payments under PEF's contracts were $467 million, $140 million and $91 million for 2007, 2006 and 2005, respectively. PEF's future obligations under these contracts are $631 million, $188 million and $42 million for 2008 through 2010, respectively.

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, $122 million and $100 million for 2007, 2006 and 2005, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $8 million, $18 million and $17 million for 2007, 2006 and 2005, respectively. Estimated future payments under these contracts of $6 million are not reflected in the contractual cash obligations table above. Included in these contracts are purchase obligations with a counterparty for pipeline capacity through 2009.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $21 million, $2 million and $10 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $22 million for 2008, $4 million each for 2009 and 2010, and $3 million each for 2011 and 2012 and $13 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006 and $13 million for 2005, with no purchases in 2007. Future obligations under these contracts are for spent fuel storage and total $5 million, $8 million, $3 million and $1 million for 2008 through 2011, respectively.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $11 million, $12 million and $8 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $21 million, $14 million, $19 million, $12 million and $12 million for 2008 through 2012, respectively, with approximately $50 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 $22 million, $21 million and $34 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $8 million and $6 million for 2008 and 2009, respectively.

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 $40 million, $42 million and $38 million for 2007, 2006 and 2005, respectively. Our purchased power expense under agreements classified as operating leases was approximately $69 million, $60 million and $14 million in 2007, 2006 and 2005, respectively.

PEC's rent expense under operating leases totaled $23 million, $25 million and $24 million during 2007, 2006 and 2005, respectively. These amounts include rent expense allocated from PESC to PEC of $6 million, $8 million and $7 million for 2007, 2006 and 2005, respectively. Purchased power expense under agreements classified as operating leases was approximately $10 million, $10 million and $11 million in 2007, 2006 and 2005, respectively.

PEF's rent expense under operating leases totaled $15 million, $16 million and $11 million during 2007, 2006 and 2005, respectively. These amounts include rent expense allocated from PESC to PEF of $6 million for 2007 and $7 million each for 2006 and 2005. Purchased power expense under agreements classified as operating leases was approximately $59 million, $49 million and $3 million in 2007, 2006 and 2005, respectively.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Buildings	**$ 267**	$ 84	**$ 30**	$ 30	**$ 237**	$ 54
Less: Accumulated amortization	**(20)**	(12)	**(13)**	(12)	**(7)**	–
Total	**$ 247**	$ 72	**$ 17**	$ 18	**$ 230**	$ 54

At December 31, 2007, 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
2008	$ 28	$ 62	$ 2	$ 35	$ 26	$ 22
2009	29	41	3	30	26	6
2010	28	25	2	17	26	4
2011	28	20	2	13	26	4
2012	28	38	2	13	26	23
Thereafter	308	554	10	127	298	424
Minimum annual payments	449	$ 740	21	$ 235	428	$ 483
Less amount representing imputed interest	(202)		(4)		(198)	
Present value of net minimum lease payments under capital leases	$ 247		$ 17		$ 230	

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides 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 2007, PEF entered into a purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from 2012 through 2027 for a total of approximately $420 million.

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for annual payments of approximately $5 million from 2007 through 2026 for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in the Statements of Income.

In 2006, PEF extended the terms of an agreement for purchased power, which is classified as a capital lease, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from 2007 through 2024 for a total of approximately $348 million. Due to the conditions of the agreement, the capital lease was not recorded on our or PEF's Balance Sheets until 2007.

In 2006, PEF entered into an agreement for purchased power, which is classified as a capital lease. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $8 million from 2012 through 2036 for a total of approximately $208 million.

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 are approximately $8 million, $7 million, $5 million, $4 million and $2 million for 2008 through 2012, respectively. Rents received under these operating leases totaled $8 million, $9 million and $8 million for 2007, 2006 and 2005, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2008 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million for 2007 and $31 million each for 2006 and 2005. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $78 million, $72 million and $63 million for 2007, 2006 and 2005, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2008 and thereafter.

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 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2007, 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, 2007, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations, which are within the scope of FIN 45. Related to the sales of businesses, the latest notice period extends until 2012 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement 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 liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2007, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $427 million, including $32 million at PEF. At December 31, 2007 and 2006, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $80 million and $60 million, respectively. These amounts include $30 million and $29 million, respectively, for PEC and $8 million for PEF at December 31, 2007 and 2006. 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 23).

D. OTHER COMMITMENTS AND CONTINGENCIES

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, 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 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 radioactive 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 presented in the trials or appeals during 2006 and 2007. 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. The trial court lifted the stay on March 22, 2006, and discovery commenced. The trial court issued a scheduling order on March 23, 2006, and the case went to trial beginning November 5, 2007. Closing arguments are anticipated in the second quarter of 2008 with a ruling expected later in 2008. The Utilities cannot predict the outcome of this matter. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment.

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 the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged 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 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 subsequently reported that the license application would be submitted by June 2008 if full funding was obtained for the project. The DOE requested $545 million for fiscal year 2007 and received $445 million. The DOE requested $495 million for fiscal year 2008. However, Congress passed an appropriations bill which allocates $390 million in fiscal year 2008 for DOE's Yucca Mountain repository program. As a result of the fiscal year budget reductions, the schedule for submitting the license application is being re-evaluated by the DOE. The impact to the Yucca Mountain repository program cannot be predicted at this time.

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation of on-site dry cask 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 their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

SYNTHETIC FUELS MATTERS

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); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; 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 (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims related to the contracts.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al*. (the Florida Global Case), asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003, and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. 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* (the North Carolina Global Case), 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. 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, but stayed 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. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The suit continues now under contract theories alone. We cannot predict the outcome of this matter.

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.

23. 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, 2007, 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 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. 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. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of Terminals and the synthetic fuels businesses as discontinued operations as described in Note 3B.

Condensed Consolidating Statement of Income
Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$ –	$ 4,768	$ 4,385	$ 9,153
Affiliate revenues	–	89	(89)	–
Total operating revenues	–	4,857	4,296	9,153
Operating expenses				
Fuel used in electric generation	–	1,764	1,381	3,145
Purchased power	–	882	302	1,184
Operation and maintenance	10	834	998	1,842
Depreciation and amortization	–	369	536	905
Taxes other than on income	–	309	192	501
Other	–	20	10	30
Total operating expenses	10	4,178	3,419	7,607
Operating (loss) income	(10)	679	877	1,546
Other income, net	27	47	4	78
Interest charges, net	203	198	187	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	528	694	1,036
Income tax (benefit) expense	(79)	117	296	334
Equity in earnings of consolidated subsidiaries	596	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	489	402	(198)	693
Discontinued operations, net of tax	15	(59)	(145)	(189)
Net income (loss)	$ 504	$ 343	$ (343)	$ 504

Condensed Consolidating Statement of Income
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$ –	$ 4,637	$ 4,087	$ 8,724
Affiliate revenues	–	41	(41)	–
Total operating revenues	–	4,678	4,046	8,724
Operating expenses				
Fuel used in electric generation	–	1,835	1,173	3,008
Purchased power	–	766	334	1,100
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	406	605	1,011
Taxes other than on income	–	309	191	500
Other	–	21	14	35
Total operating expenses	14	4,021	3,202	7,237
Operating (loss) income	(14)	657	844	1,487
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	182	166	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	530	699	906
Income tax (benefit) expense	(123)	174	288	339
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	(16)
Income (loss) from continuing operations	579	340	(368)	551
Discontinued operations, net of tax	(8)	359	(331)	20
Net income (loss)	$ 571	$ 699	$ (699)	$ 571

Condensed Consolidating Statement of Income
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$ –	$ 3,956	$ 3,992	$ 7,948
Affiliate revenues	–	188	(188)	–
Total operating revenues	–	4,144	3,804	7,948
Operating expenses				
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	–	337	589	926
Taxes other than on income	4	279	177	460
Other	–	(5)	2	(3)
Total operating expenses	16	3,480	3,064	6,560
Operating (loss) income	(16)	664	740	1,388
Other income (expense), net	66	(1)	(53)	12
Interest charges, net	305	163	107	575
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	500	580	825
Income tax (benefit) expense	(64)	96	266	298
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' income, net of tax	–	(4)	–	(4)
Income (loss) from continuing operations	693	400	(570)	523
Discontinued operations, net of tax	4	(26)	195	173
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$ 697	$ 374	$ (374)	$ 697

Condensed Consolidating Balance Sheet
December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 7,600	$ 9,005	$ 16,605
Current assets				
Cash and cash equivalents	185	43	27	255
Short-term investments	–	–	1	1
Notes receivable from affiliated companies	157	149	(306)	–
Deferred fuel cost	–	6	148	154
Assets to be divested	–	48	4	52
Prepayments and other current assets	21	1,211	1,081	2,313
Total current assets	363	1,457	955	2,775
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,969	–	(10,969)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	149	1,551	1,551	3,251
Total deferred debits and other assets	11,118	1,552	(5,764)	6,906
Total assets	$ 11,481	$ 10,609	$ 4,196	$ 26,286
Capitalization				
Common stock equity	$ 8,422	$ 3,052	$ (3,052)	$ 8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	81	3	84
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,686	3,183	8,466
Total capitalization	11,019	6,162	155	17,336
Current liabilities				
Current portion of long-term debt	–	577	300	877
Short-term debt	201	–	–	201
Notes payable to affiliated companies	–	227	(227)	–
Regulatory liabilities	–	173	–	173
Liabilities to be divested	–	8	–	8
Other current liabilities	215	1,028	746	1,989
Total current liabilities	416	2,013	819	3,248
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	59	302	361
Regulatory liabilities	–	1,316	1,223	2,539
Accrued pension and other benefits	12	347	404	763
Capital lease obligations	–	224	15	239
Other liabilities and deferred credits	34	488	1,278	1,800
Total deferred credits and other liabilities	46	2,434	3,222	5,702
Total capitalization and liabilities	$ 11,481	$ 10,609	$ 4,196	$ 26,286

Condensed Consolidating Balance Sheet
December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 6,337	$ 8,908	$ 15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets to be divested	–	121	845	966
Prepayments and other current assets	27	1,060	1,029	2,116
Total current assets	259	1,258	2,097	3,614
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,556	1,511	3,193
Total deferred debits and other assets	10,866	1,557	(5,575)	6,848
Total assets	$ 11,125	$ 9,152	$ 5,430	$ 25,707
Capitalization				
Common stock equity	$ 8,286	$ 2,708	$ (2,708)	$ 8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities to be divested	–	72	176	248
Other current liabilities	210	1,224	814	2,248
Total current liabilities	210	1,497	1,113	2,820
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	251	312
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	557	1,261	1,851
Total deferred credits and other liabilities	47	2,086	3,530	5,663
Total capitalization and liabilities	$ 11,125	$ 9,152	$ 5,430	$ 25,707

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 76	$ 489	$ 687	$ 1,252
Investing activities				
Gross property additions	–	(1,218)	(755)	(1,973)
Nuclear fuel additions	–	(44)	(184)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	624	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	(1,413)
Proceeds from sales of available-for-sale securities and other investments	21	640	791	1,452
Changes in advances to affiliates	(99)	(112)	211	–
Return of investment in consolidated subsidiary	340	–	(340)	–
Other investing activities	(31)	32	29	30
Net cash provided (used) by investing activities	231	(1,291)	(397)	(1,457)
Financing activities				
Issuance of common stock	151	–	–	151
Dividends paid on common stock	(627)	–	–	(627)
Dividends paid to parent	–	(10)	10	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	176
Net increase in short-term debt	25	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	739
Retirement of long-term debt	–	(124)	(200)	(324)
Changes in advances from affiliates	–	151	(151)	–
Other financing activities	–	49	6	55
Net cash (used) provided by financing activities	(275)	805	(335)	195
Net increase (decrease) in cash and cash equivalents	32	3	(45)	(10)
Cash and cash equivalents at beginning of year	153	40	72	265
Cash and cash equivalents at end of year	$ 185	$ 43	$ 27	$ 255

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$ 1,295	$ 1,110	$ (404)	$ 2,001
Investing activities				
Gross property additions	–	(865)	(707)	(1,572)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	415	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	419	(1,035)	127
Financing activities				
Issuance of common stock	185	–	–	185
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Net decrease in short-term debt	–	(102)	(73)	(175)
Proceeds from issuance of long-term debt, net	397	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Changes in advances from affiliates	–	(243)	243	–
Other financing activities	(8)	(8)	(52)	(68)
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$ 153	$ 40	$ 72	$ 265

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	$ 509	$ 701	$ 1,467
Investing activities				
Gross property additions	–	(714)	(599)	(1,313)
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	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	(2)	(40)
Net cash provided (used) by investing activities	690	(320)	(1,514)	(1,144)
Financing activities				
Issuance of common stock	208	–	–	208
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Net decrease in short-term debt	(170)	(191)	(148)	(509)
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	50	(9)	32
Net cash (used) provided by financing activities	(713)	27	913	227
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$ 239	$ 239	$ 127	$ 605

24. 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)	Second (a)	Third (a)	Fourth (a)
2007				
Operating revenues	**$ 2,072**	**$ 2,129**	**$ 2,750**	**$ 2,202**
Operating income	**351**	**301**	**610**	**284**
Income from continuing operations	**159**	**106**	**327**	**101**
Net income (loss)	**275**	**(193)**	**319**	**103**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.63**	**0.42**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Diluted earnings per common share				
Income from continuing operations	**0.62**	**0.41**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Dividends declared per common share	**0.610**	**0.610**	**0.610**	**0.615**
Market price per share – High	**51.60**	**52.75**	**49.48**	**50.25**
– Low	**47.05**	**45.15**	**43.12**	**44.75**
2006				
Operating revenues	$ 1,985	$ 2,083	$ 2,599	$ 2,057
Operating income	295	332	570	290
Income from continuing operations	67	110	268	106
Net income (loss)	45	(47)	319	254
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Dividends declared per common share	0.605	0.605	0.605	0.610
Market price per share – High	45.31	45.16	46.22	49.55
– Low	42.54	40.27	42.05	44.40

(a) Operating results have been restated for discontinued operations.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. The 2007 and 2006 amounts were restated for discontinued operations (See Note 3).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2007				
Operating revenues	**$ 1,058**	**$ 996**	**$ 1,286**	**$ 1,045**
Operating income	**235**	**180**	**375**	**179**
Net income	**124**	**88**	**204**	**85**
2006				
Operating revenues	$ 978	$ 936	$ 1,200	$ 972
Operating income	189	174	346	178
Net income	86	76	189	106

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.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2007				
Operating revenues	**$ 1,011**	**$ 1,129**	**$ 1,456**	**$ 1,153**
Operating income	**117**	**125**	**235**	**109**
Net income	**61**	**68**	**138**	**50**
2006				
Operating revenues	$ 1,007	$ 1,147	$ 1,399	$ 1,086
Operating income	117	167	237	122
Net income	53	87	125	63

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE 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, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and the Company's internal control over financial reporting as of December 31, 2007 and have issued our reports thereon dated February 28, 2008 (which report on consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006); 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
February 28, 2008

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, 2007					
Uncollectible accounts	**$ 28**	**$ 26**	**$ (1)**	**$ (24)**	**$ 29**
Fossil fuel plants dismantlement reserve	**145**	**1**	**–**	**(2)**	**144**
Nuclear refueling outage reserve	**16**	**15**	**–**	**(29)**	**2**
DECEMBER 31, 2006					
Uncollectible accounts	$ 19	$ 29	$ –	$ (20)	$ 28
Fossil fuel plants dismantlement reserve	145	1	–	(1)	145
Nuclear refueling outage reserve	2	14	–	–	16
DECEMBER 31, 2005					
Uncollectible accounts	$ 22	$ 16	$ –	$ (19)	$ 19
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	12	11	–	(21) (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, 2007 and 2006, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 28, 2008 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006); 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
February 28, 2008

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, 2007					
Uncollectible accounts	**$ 5**	**$ 10**	**$ 2**	**$ (11)**	**$ 6**
DECEMBER 31, 2006					
Uncollectible accounts	$ 4	$ 9	$ –	$ (8)	$ 5
DECEMBER 31, 2005					
Uncollectible accounts	$ 10	$ 5	$ –	$ (11)	$ 4

(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, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and have issued our report thereon dated February 28, 2008 (which report on financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006); 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
February 28, 2008

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, 2007					
Uncollectible accounts	**$ 8**	**$ 14**	**$ 1**	**$ (13)**	**$ 10**
Fossil fuel plants dismantlement reserve	**145**	**1**	–	**(2)**	**144**
Nuclear refueling outage reserve	**16**	**15**	–	**(29)**	**2**
DECEMBER 31, 2006					
Uncollectible accounts	$ 6	$ 14	$ –	$ (12)	$ 8
Fossil fuel plants dismantlement reserve	145	1	–	(1)	145
Nuclear refueling outage reserve	2	14	–	–	16
DECEMBER 31, 2005					
Uncollectible accounts	$ 2	$ 10	$ –	$ (6)	$ 6
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	12	11	–	(21) (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

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to 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 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 15d-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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Progress Energy; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted 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, 2007. 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. 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, 2007, Progress Energy maintained effective internal control over financial reporting.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the internal control over financial reporting of Progress Energy as of December 31, 2007, as stated in their report which is included below.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has been no change in Progress Energy's internal control over financial reporting during the quarter ended December 31, 2007, 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 the internal control over financial reporting of Progress Energy, Inc., (the Company) as of December 31, 2007, 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, included in the accompanying *Management’s Report on Internal Control Over Financial Reporting* . Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2007, 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, 2007, of the Company and our report dated February 28, 2008, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

ITEM 9A(T). CONTROLS AND PROCEDURES

PEC

DISCLOSURE CONTROLS AND PROCEDURES

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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of PEC's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. PEC'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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PEC; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America; (3) provide reasonable assurance that receipts and expenditures of PEC are being made only in accordance with authorizations of management and directors of PEC; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PEC'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 PEC's internal control over financial reporting at December 31, 2007. 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. Management's assessment included an evaluation of the design of PEC'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, 2007, PEC maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEC's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEC's registered public accounting firm pursuant to the temporary rules of the SEC that permit PEC to provide only management's report in this annual report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has been no change in PEC's internal control over financial reporting during the quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PEF

DISCLOSURE CONTROLS AND PROCEDURES

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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of PEF's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. PEF'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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PEF; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America; (3) provide reasonable assurance that receipts and expenditures of PEF are being made only in accordance with authorizations of management and directors of PEF; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PEF'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 PEF's internal control over financial reporting at December 31, 2007. 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. Management's assessment included an evaluation of the design of PEF'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, 2007, PEF maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEF's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEF's registered public accounting firm pursuant to the temporary rules of the SEC that permit PEF to provide only management's report in this annual report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has been no change in PEF's internal control over financial reporting during the quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

a) Information on Progress Energy, Inc.'s directors is set forth in Progress Energy's definitive proxy statement for the 2008 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 2008 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 written request.

We intend to satisfy the disclosure requirement under Item 5.05 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 Web site cited above.

d) The board of directors has determined that Carlos A. Saladrigas and Theresa M. Stone are the "Audit Committee Financial Experts," as that term is defined in the rules promulgated by the SEC pursuant to the Sarbanes-Oxley Act of 2002, and have designated them as such. Both Mr. Saladrigas and Ms. Stone are "independent," as that term is defined in the general independence standards of the New York Stock Exchange listing standards.

e) Information regarding our compliance with Section 16(a) of the Securities Exchange Act of 1934 and certain corporate governance matters is set forth in Progress Energy's and PEC's definitive proxy statements for the 2008 Annual Meeting of Shareholders and incorporated by reference herein.

f) The following are available on our Web site cited above and in print at no cost:

- €€Audit and Corporate Performance 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 2008 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 2008 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 2008 Annual Meeting of Shareholders and incorporated herein by reference.

Information regarding any person PEC knows to be the beneficial owner of more than five percent of any class of its voting securities is set forth in its definitive proxy statement for the 2008 Annual Meeting of Shareholders and incorporated herein by reference.

b) Information on security ownership of Progress Energy's and PEC's management is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2008 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 2008 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, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2008 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 has adopted policies and procedures for approving all audit and permissible nonaudit services rendered by Deloitte, and the fees billed for those services. The Controller is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. The Audit Committee specifically preapproved the use of Deloitte for audit, audit-related, tax and nonaudit services, subject to the limitations of our preapproval policy.

The preapproval policy requires management to obtain specific preapproval 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 not be considered for approval except in limited instances, 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 five percent 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 Controller 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 services. The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and New York Stock Exchange standards. The Audit Committee will assess the adequacy of this policy and related procedure as it deems necessary and revise accordingly.

Information regarding principal accountant fees and services is set forth, respectively, in Progress Energy’s and PEC’s definitive proxy statements for the 2008 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.

	2007	2006
Audit fees	**$ 1,576,000**	$ 906,000
Audit-related fees	**21,000**	44,000
Tax fees	**248,000**	103,000
All other fees	**–**	4,000
Total	**$ 1,845,000**	$ 1,057,000

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 internal control over financial reporting; (iii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of PEF, (iv) SEC filings, (v) accounting consultations arising as part of the audits and (vi) comfort letters.

Audit-related fees include fees billed for (i) special procedures and letter reports, (ii) benefit plan audits when fees are paid by PEF rather than directly by the plan; and (iii) 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 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.
Date: February 28, 2008	(Registrant)
	By: /s/ William D. Johnson (William D. Johnson) Chairman, 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 and Controller

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

Signature	Title	Date
/s/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2008
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	February 28, 2008
/s/ David L. Burner (David L. Burner)	Director	February 28, 2008
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	February 28, 2008
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	February 28, 2008
/s/ Robert W. Jones (Robert W. Jones)	Director	February 28, 2008
/s/ W. Steven Jones	Director	February 28, 2008

/s/ E. Marie McKee (E. Marie McKee)	Director	February 28, 2008
/s/ John H. Mullin, III (John H. Mullin, III)	Director	February 28, 2008
/s/ Charles W. Pryor, Jr. (Charles W. Pryor, Jr.)	Director	February 28, 2008
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	February 28, 2008
/s/ Theresa M. Stone (Theresa M. Stone)	Director	February 28, 2008
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	February 28, 2008

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.

CAROLINA POWER & LIGHT COMPANY

Date: February 28, 2008

(Registrant)

By: /s/ William D. Johnson
(William D. Johnson)
Chairman

By: /s/ Lloyd M. Yates
Lloyd M. Yates
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/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2008
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2008
/s/ James Scarola (James Scarola)	Director	February 28, 2008
/s/ Peter M. Scott III (Peter M. Scott III)	Director	February 28, 2008
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	February 28, 2008

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: February 28, 2008	(Registrant)
	By: /s/ Jeffrey J. Lyash Jeffrey J. Lyash 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/ William D. Johnson (William D. Johnson)	Chairman	February 28, 2008
/s/ Michael A. Lewis (Michael A. Lewis)	Director	February 28, 2008
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 28, 2008
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2008
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 28, 2008
/s/ Peter M. Scott III (Peter M. Scott III)	Director	February 28, 2008
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	February 28, 2008

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		
*3a(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		
*3a(5)	Amended Articles of Incorporation of Progress Energy, Inc., as amended on May 10, 2006 (filed as Exhibit 3.A to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274).	X		
*3a(6)	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(1)	By-Laws of Progress Energy, Inc., as amended on May 10, 2006 (filed as Exhibit 3.B to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274).	X		
3b(2)	By-Laws of Carolina Power & Light Company, as amended on September 17, 2007.		X	

*3b(3)	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	X	

	amended, 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 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	X

	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 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); and the	X

Forty-sixth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on September 19, 2007); and the Forty-seventh Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed

	with the SEC on December 13, 2007).			
*4b(4)	Indenture, dated as of December 7, 2005, between Florida Power Corporation 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 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	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	
*4d	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	
*4e	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 Report on Form 8-K dated December 12, 2000, File No. 1-3382).	X		
*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		X	

	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).	
*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,	X

	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).			
*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	
*10b(1)	Progress Energy, Inc. $1,130,000,000 5-Year Revolving Credit Agreement dated as of May 3, 2006 (filed as Exhibit 10(c) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).	X		
*10b(2)	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(3)	Amendment dated as of May 3, 2006, to the 5-Year $450,000,000 Credit Agreement among PEF and certain lenders, dated March 28, 2005 (filed as Exhibit 10(e) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).			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	
*10b(5)	Amendment dated as of May 3, 2006, to the 5-¼-Year $450,000,000 Credit Agreement among PEC and certain lenders, dated March 28, 2005 (filed as Exhibit 10(d) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).		X	
-+*10c(1)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).		X	
+*10c(2)	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(3)	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(4)	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(5)	2002 Progress Energy, Inc. Equity Incentive Plan, Amended and Restated effective January 1, 2007 (filed as Exhibit 10c(5) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on	X	X	X

	March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).			
+*10c(6)	Amended and Restated Broad-Based Performance Share Sub-Plan, Exhibit B to the 2002 Progress Energy, Inc. Equity Incentive Plan, effective January 1, 2007 (filed as Exhibit 10c(6) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(7)	Amended and Restated Executive and Key Manager Performance Share Sub-Plan, Exhibit A to the 2002 Progress Energy, Inc. Equity Incentive Plan (effective January 1, 2007) (filed as Exhibit 10c(7) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(8)	Executive and Key Manager 2007 Performance Share Sub-Plan, Exhibit A to the 2007 Equity Incentive Plan, effective January 1, 2007 (filed as Exhibit 10.1 to Current Report on Form 8-K dated July 16, 2007, File No. 1-15929, No. 1-3382 and No. 1-3274).	X	X	X
+*10c (9)	Amended and Restated Management Incentive Compensation Plan of Progress Energy, Inc., effective January 1, 2007 (filed as Exhibit 10c(8) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(10)	Amended and Restated Management Deferred Compensation Plan of Progress Energy, Inc., effective as of January 1, 2007 (filed as Exhibit 10c(9) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(11)	Amended and Restated Management Change-in-Control Plan of Progress Energy, Inc., effective as of January 1, 2007 (filed as Exhibit 10c(10) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(12)	Amended and Restated Non-Employee Director Deferred Compensation Plan of Progress Energy, Inc., effective January 1, 2007 (filed as Exhibit 10c(11) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X

+*10c(13)	Amended and Restated Restoration Retirement Plan of Progress Energy, Inc., effective January 1, 2007 (filed as Exhibit 10c(12) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X

+*10c(14)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., effective January 1, 2007 (filed as Exhibit 10c(13) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(15)	Amended and Restated Non-Employee Director Stock Unit Plan of Progress Energy, Inc., effective January 1, 2007 (filed as Exhibit 10c(14) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*10c(16)	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(17)	Form of Restricted Stock Unit Award Agreement as of March 20, 2007 (filed as Exhibit 10.1 to Current Report on Form 8-K dated March 26, 2007, File No. 1- 15929, No. 1-3382 and No. 1-3274).	X	X	X
+*10c(18)	Form of Employment Agreement dated May 8, 2007 between (i) Progress Energy Service Company, LLC and Robert McGehee, John R. McArthur and Peter M. Scott III; (ii) PEC and Lloyd M. Yates, Fredrick N. Day IV, Paula M. Sims, William D. Johnson and Clayton S. Hinnant; and (iii) PEF and Jeffrey A. Corbett and Jeffrey J. Lyash (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-15929, No. 1-3382 and No. 1-3274).	X	X	X
+*10c(19)	Form of Employment Agreement between Progress Energy Service Company, LLC and Mark F. Mulhern, dated September 18, 2007 (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-15929, No. 1-3382 and No. 1-3274).	X		
+*10c(20)	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(21)	Selected Executives Supplemental Deferred		X	

Compensation Program Agreement, dated August, 1996, between CP&L and C. S. Hinnant (filed as Exhibit 10c(22) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on February 29, 2006, File No. 1-3382, No. 1-15929, and No. 1-3274).

+*10c(22)	Form of Executive Permanent Life Insurance Agreement (filed as Exhibit 10c(23) to Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on February 28, 2006, File No. 1-3382, No. 1-15929, and No. 1-3274).		
*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 g) Letter Agreement between FGT and PEF, dated January 31, 2005, (filed as Exhibit 10.1 to Current Report on Form 8-K/A filed March 15, 2005). (Confidential treatment has been requested for portions of this exhibit. These portions have been omitted from the above-referenced Current Report and submitted separately to the SEC.)	X	X
12(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		
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 3b(2)

B Y - L A W S

of

CAROLINA POWER & LIGHT COMPANY

Raleigh, North Carolina

(As Amended September 17, 2007)

Meetings of Stockholders

Section 1. The annual meeting of the stockholders of the Company shall be held at the principal office of the Company, on the second Wednesday of May in each year, if not a legal holiday, and if a legal holiday, then on the next day not a legal holiday, at ten o'clock A.M., or at such other date, or hour, or at such other place within or without the State of North Carolina as stated in the notice of the meeting as the Board of Directors may determine.

Section 2. Special meetings of the stockholders of the Company may be held upon call by a majority of the Board of Directors or of the Executive Committee, or by the Chairman of the Board, or by the President of the Company, at the principal office of the Company or at such other place within or without the State of North Carolina, and at such time, as may be stated in the call and notice.

Section 3. Written notice of the time and place of every meeting of stockholders may be given, and shall be deemed to have been duly given, by mailing the same at least ten, but not more than sixty, days prior to the meeting, to each stockholder of record, entitled to vote at such meeting, and addressed to him at his address as it appears on the records of the Company, with postage thereon prepaid. Notice may also be given by any other lawful means.

Section 4. In accordance with Section 55-7-20 of the General Statutes of North Carolina, the Company, or an officer having charge of the record of stockholders of the Company, shall prepare a list of stockholders which shall be available for inspection by stockholders, or their agents or attorneys.

Section 5. The holders of a majority of the stock of the Company having voting powers must be present in person or represented by proxy at each meeting of the stockholders to constitute a quorum; absent such quorum, the meeting may be adjourned by a majority of shares voting on a motion to adjourn. If such adjournment is for less than thirty days, notice other than announcement at the meeting need not be given. At any adjourned meeting at which a quorum shall be present or represented, any business may be transacted which might have been transacted at the original meeting.

Section 6. (a) When a quorum is present at any meeting, the vote of the holders of a majority of the outstanding stock having voting power present in person or represented by proxy shall decide any question brought before such meeting, unless the question is one upon which by express provision of any applicable statute or of the Charter a different vote is required, in which case such express provision shall govern and control the decision of such question.

(b) To be properly brought before a meeting of shareholders, business must be (i) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Board of Directors, (ii) otherwise properly brought before the meeting by or at the direction of the Board of Directors or (iii) otherwise properly brought before an annual meeting by a shareholder of the Company who was a shareholder of record at the time of the giving of notice provided for in Section 3 of these By-Laws and who is entitled to vote at the meeting. In addition to any other applicable requirements, for business to be properly brought before an annual meeting by a shareholder, the shareholder must give timely notice of the proposal in writing to the Secretary of the Company. To be timely, a shareholder's notice must be received by the Secretary of the Company at the principal executive offices of the Company not later than the close of business on the 60th day prior to the first anniversary of the immediately preceding year's annual meeting. In no event shall the public announcement of an adjournment or postponement of an annual meeting or the fact that an annual meeting is held after the anniversary of the preceding annual meeting commence a new time period for the giving of a shareholder notice as described above. A shareholder's notice shall set forth as to each matter the shareholder proposes to bring before the meeting (i) a brief description of the business desired to be brought before the annual meeting, including the complete text of any resolutions to be presented at the annual meeting with respect to such business, (ii) the reasons for conducting such business at the annual meeting, (iii) the name and address of record of the shareholder and the beneficial owner, if any, on whose behalf the proposal is made, (iv) the class and number of shares of the Company which are owned by the shareholder and such beneficial owner, (v) a representation that the shareholder is a holder of record of shares of the Company entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to propose such business, and (vi) any material interest of the shareholder and such beneficial owner in such business.

In the event that a shareholder attempts to bring business before a meeting without complying with the procedures set forth in this Section 6(b), such business shall not be transacted at such meeting. The Chairman of the Board of Directors, or any other individual presiding over the meeting pursuant to Section 8 of these By-Laws, shall have the power and duty to determine whether any proposal to bring business before the meeting was made in accordance with the procedures set forth in this Section 6(b), and, if any business is not proposed in compliance with this Section, to declare that such defective proposal shall be disregarded and that such proposed business shall not be transacted at such meeting.

Section 7. The Board of Directors in advance of any meeting of stockholders may appoint two voting inspectors to act at any such meeting or adjournment thereof. If they fail to make such appointment, or if their appointees or any of them fail to appear at the meeting of stockholders, the chairman of the meeting may appoint such inspectors or any inspector to act at that meeting.

Section 8. Meetings of the stockholders shall be presided over by the Chairman of the Board of Directors, or, if he is not present, the President, or, if the President is not present, a Vice President, or if neither of said officers is present, by a chairman pro tem to be elected at the meeting. The

Secretary of the Company shall act as secretary of such meetings, if present, but if not present, some person shall be appointed by the presiding officer to act during the meeting.

Section 9. Each holder of Preferred Stock and/or Common Stock shall at every meeting of the stockholders be entitled to one vote in person or by proxy for each share of such stock held by such stockholder. Except where the transfer books of the Company have been closed or a date has been fixed as a record date for the determination of its stockholders entitled to vote, no share of stock shall be voted at any election for directors which has been transferred on the books of the Company within twenty days next preceding such election of directors.

Directors and Meetings of Directors

Section 10. (a) The number of directors of the Company shall not be less than eleven (11) nor more than fifteen (15). The authorized number of directors, within the limits above specified, shall be determined by the affirmative vote of a majority of the whole board given at any regular or special meeting of the Board of Directors, provided that, the number of directors shall not be reduced to a number less than the number of directors then in office unless such reduction shall become effective only at and after the next ensuing meeting of the shareholders for the election of directors. This subsection (a) was adopted by the stockholders of the Company.

(b) Any employee of the Company or any of its affiliates who currently serves, or who is, in the future, elected to serve on the Board of Directors of the Company must remain an employee of the Company or one of its affiliates in order to be qualified to serve on the Board of Directors. The term of any such Director's service on the Board will terminate immediately upon termination of his or her employment with the Company and its affiliates.

(c) The directors shall appoint from among their number a Chairman, who shall serve at the pleasure of the Board. Members of the Board of Directors of the Company who are full-time employees of the Company shall retire from the Board upon their retirement from employment or upon attaining the age of 65 years, whichever occurs first; provided, however, that the Chairman of the Board, if then a full-time employee of the Company, shall be eligible to continue as a member of the Board until the first Annual Meeting of Shareholders occurring at least one year after retirement from employment or after attaining the age of 65 years, whichever occurs first, if so requested to remain by the Board. Those persons who are not employed full-time by the Company shall not be eligible for election as a Director in any calendar year (or subsequent year) in which he or she has reached or will reach the age of 73 years, unless requested by the Chairman of the Board and approved on an annual basis by the full Board. Otherwise, any Director who reaches the age of 73 during a term of office shall resign as of the first day of the month so following unless otherwise determined by the Board.

(d) The election of directors shall be held at the annual meeting of stockholders. The directors, other than those who may be elected under circumstances specified in the Company's Restated Charter, as it may be amended, by the holders of any class of stock having a preference over the Common Stock as to dividends or in liquidation, shall be classified into three classes, as nearly equal in number as possible. The initial terms of directors first elected or re-elected by the stockholders on the date this amendment to the By-Laws is adopted shall be for the following terms of office:

Class I:	One year
Class II:	Two years
Class III:	Three years

and until their successors shall be elected and shall qualify. Upon the expiration of the initial term specified for each class of directors their successors shall be elected for three-year terms or until such time as their successors shall be elected and qualified. In the event of any increase or decrease in the number of directors, the additional or eliminated directorships, shall be classified or chosen so that all classes of directors shall remain or become equal in number, as nearly as possible. This subsection (d) was adopted by the stockholders of the Company.

(e) Subject to the rights of holders of any securities or obligations of the Company conferring special rights regarding election of directors, nominations for the election of directors shall be made by the Board of Directors or by any shareholder entitled to vote in elections of directors; provided however, that any shareholder entitled to vote in the election of directors may nominate one or more persons for election as directors only at an annual meeting and if written notice of such shareholder's intent to make such nomination or nominations has been received, either by personal delivery or by United States registered or certified mail, postage prepaid, by the Secretary of the Company at the principal executive offices of the Company not later than the close of business on the 120th calendar day before the date of the Company's proxy statement released to shareholders in connection with the previous year's annual meeting. In no event shall the public announcement of an adjournment or postponement of an annual meeting commence a new time period for the giving of a shareholder's notice as described above. Each notice shall set forth (i) the name and address of record of the shareholder who intends to make the nomination, the beneficial owner, if any, on whose behalf the nomination is made and of the person or persons to be nominated, (ii) the class and number of shares of the Company that are owned by the shareholder and such beneficial owner, (iii) a representation that the shareholder is a holder of record of shares of the Company entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice, (iv) a description of all arrangements, understandings or relationships between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder, and (v) such other information regarding each nominee proposed by such shareholder as would be required to be disclosed in solicitations of proxies for election of directors in an election contest, or is otherwise required to be disclosed, pursuant to the proxy rules of the Securities and Exchange Commission, had the nominee been nominated, or intended to be nominated, by the Board of Directors, and shall include a consent signed by each such nominee to serve as a director of the Company if so elected. In the event that a shareholder attempts to nominate any person without complying with the procedures set forth in this Section 10 (e), such person shall not be nominated and shall not stand for election at such meeting. The Chairman of the Board of Directors, or any other individual presiding over the meeting pursuant to Section 8 of these By-Laws, shall have the power and duty to determine whether a nomination proposed to be brought before the meeting was made in accordance with the procedures set forth in this Section 10 (e) and, if any proposed nomination is not in compliance with this Section 10 (e), to declare that such defective proposal shall be disregarded.

Section 11. In case of any vacancy in the number of directors through death, resignation, disqualification, increase in the number of directors or other cause, the remaining directors present at the meeting, by affirmative vote of a majority thereof, though less than a quorum, may elect a successor to hold office until the next shareholders' meeting at which directors are elected and until the election of his successor.

Section 12. Regular meetings of the Board of Directors shall be held at times fixed by resolution of the Board, and special meetings may be held upon the written call of the Executive Committee, or by the Chairman of the Board, or by the President or by any two directors; and the Secretary or officer performing his duties shall give reasonable notice of all meetings of directors; provided, that a meeting may be held without notice immediately after the annual election, and notice need not be given of regular meetings held at times fixed by resolution of the Board. Meetings may be held at any time without notice if all the directors are present, or if those not present waive notice either before or after the meeting. All regular and special meetings shall be held at the principal offices of the Company, provided that the Board, from time to time, may order that any meeting be held elsewhere within or without the State of North Carolina. A majority of the whole Board of Directors shall constitute a quorum, and the act of a majority of the directors present at a meeting at which a quorum is present shall be the act of the Board of Directors, unless a greater proportion is required by the Charter.

Section 13. The business and affairs of the Company shall be managed by its Board of Directors, which may exercise all such powers of the Company and do all such lawful acts and things which are not by law or by the Charter directed or required to be exercised or done by the stockholders; provided, however, that the officers of the Company shall, without prior action of the Board of Directors, perform all acts and things incidental to the usual and ordinary course of the business in which the Company is engaged as hereinafter provided by the By-Laws or as may hereafter be delegated by the Board of Directors. A majority of the Board of Directors may create one or more Committees and appoint other members of the Board of Directors to serve on such Committees. Each such Committee shall have two or more members, who serve at the pleasure of the Board of Directors. Any such Committee may exercise authority over any matters except those matters described in Section 55-8-25(e) of the General Statutes of North Carolina.

Section 14. A majority of the whole Board of Directors, present at any meeting held after their election in each year, may appoint an Executive Committee, to consist of three or more directors, which Committee shall have and may exercise, during the intervals between meetings of the Board, by a majority vote of those present at a meeting, all the powers vested in the Board, except the following matters as more fully described in Section 55-8-25(e) of the General Statutes of North Carolina:

- Authorize distributions;

- Approve or propose to shareholders action that is by law required to be approved by the shareholders;

- Fill vacancies on the Board of Directors or on any of its Committees;

- Amend the Company's Articles of Incorporation pursuant to N.C.G.S. э55-10-102;

- Adopt, amend or repeal the Company's By-Laws;

- Approve a plan of merger not requiring shareholder approval;

- Authorize or approve reacquisition of shares, except according to a formula or method prescribed by the Board of Directors; or

- Authorize or approve the issuance or sale or contract for sale of shares, or determine the designation and relative rights, preferences, and limitations of a class or series of shares.

A majority of the whole Board of Directors present at any meeting shall have the power at any time to change the membership of such Committee and to fill vacancies in it. The Executive Committee may make rules for the conduct of its business. A majority of the members of said Committee shall constitute a quorum. The Chairman of the Executive Committee shall be appointed by the Board of Directors from the membership of the Executive Committee.

Notices

Section 15. Notices to directors or stockholders shall be in writing and given personally or by mail to the directors and by mail to the stockholders at their addresses appearing on the books of the Company; provided, however, that no notice need be given any stockholder or director whose address is outside of the United States. Notice by mail shall be deemed to be given at the time when the same shall be mailed. Notice to directors may also be given verbally, or by telegram, or cable, and any such notice shall be deemed to be given when delivered to and accepted for transmittal by an office of the transmitting company.

Section 16. Whenever any notice is required to be given under the provisions of applicable statutes or of the Charter or of these By-Laws, a waiver thereof in writing, signed by the person or persons entitled to said notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice in apt time.

Officers, Their Authority, and Their Terms of Office

Section 17. The Board of Directors shall annually at its first meeting held after the Annual Meeting of Stockholders, or as soon thereafter as may be practical, elect the officers of the Company, who shall consist of a President, one or more Senior Executive Vice Presidents and Executive Vice Presidents, two or more Senior Vice Presidents, three or more Vice Presidents, a Secretary, a Treasurer, a Controller and such other officers or assistant officers and agents as may be appointed by the Board of Directors. At other times, the Board of Directors or any Committee to which it delegates the authority to do so may elect officers to fill any new office or a vacancy in any office occurring by virtue of the incumbent's death, resignation, removal or otherwise at any duly convened meeting of the Board or of the Committee. The officer shall serve for the period specified or until a successor is chosen. From time to time the Board of Directors may also elect a Vice Chairman who shall have such duties as described herein and as may from time to time be directed. Any two offices may be held by the same person, but no officer may act in more than one capacity where action of two or more officers is required. The Vice Chairman, if any, of the Board of Directors shall be chosen from among the Directors, but the other officers need not be Directors of the Company.

Section 18. The Board of Directors shall appoint the Chief Executive Officer who shall be either the Chairman, the Vice Chairman or the President of the Company. In the event the Chief Executive Officer is unavailable at the time for needed action, or in other circumstances as directed by the Chief Executive Officer, then the Chairman, the Vice Chairman, if any, or the President if there is no Vice Chairman, who is not then serving as Chief Executive Officer, shall be the next officer in line of authority to perform the duties of Chief Executive Officer. If the Chairman, the Vice Chairman and the President should be unavailable at the time for needed action, or in other circumstances as directed by the Chief Executive Officer, then the next officer in line of authority to perform the duties of the Chief Executive Officer shall be a Senior Executive Vice President or Executive Vice President as designated by the Chief Executive Officer.

Section 19. Any officer may be reassigned duties by appropriate members of Senior Management at any time. Any officer may be removed from office at any time by the Board of Directors, or by any Committee to which it delegates the authority to remove officers from office, without prejudice to the rights of the officer removed under an employment agreement in writing previously duly authorized by the Board of Directors or an Executive Committee of the Board of Directors. Any officer may resign at any time by giving written notice to the Board of Directors, the President or any other officer of the Company. Such resignation shall take effect at the time specified therein, and, unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective.

Section 20. The Board of Directors or the Chief Executive Officer of the Company may require the Treasurer and any other officer, employee or agent of the Company to give bond, in such sum and with such surety or sureties as either shall determine, for the faithful discharge of their duties.

Section 21. Unless otherwise provided by the Board of Directors, the Company's Chief Executive Officer is vested with full power, authority, and the duty, to perform in person, and by delegation of authority to subordinate officers and employees of the Company, all acts and things deemed by him to be reasonably necessary or desirable to direct, handle, and manage, and in general carry on the Company's business transactions authorized by its Charter, in respect to all matters except those which by law must be performed by the Directors, including but not limited to the following: (a) constructing and contracting for the construction of generating plants authorized by the Directors; (b) operating and maintaining generating plants and appurtenant works; (c) constructing, maintaining, and operating substations, lines and all other facilities, appurtenant to the transmission, distribution and delivery of electricity; (d) acquiring by direct purchase, gift, exchange, or by condemnation, all rights of way, easements, lands, and estates in lands, flowage and water rights; (e) acquiring, maintaining and disposing of tools, machinery, appliances, materials, vehicles, and other appurtenant facilities; (f) employing, and fixing compensation of, Company personnel (except that the compensation of the Chief Executive Officer and the other Company employees who are members of the Board shall be fixed by the Board of Directors) in compliance with any procedures established by the Board; (g) borrowing money from time to time for terms not exceeding three years, and in connection therewith pledging the credit of the Company and executing unsecured loan agreements, promissory notes, and other desirable instruments evidencing obligations to the lender; (h) fixing the rates and conditions of service and dealing with regulatory bodies in respect thereto, and promoting the use of electricity by means of sales representatives, advertising and otherwise; (i) collecting and keeping accounts of all monies due the Company and making and preserving records of the Company's properties and accounts and fiscal affairs; and (j) possessing, preserving, and protecting all property, assets, and interests of the Company and instituting, prosecuting, intervening in, and defending actions and proceedings in any court or before any administrative agency or tribunal affecting the Company's interests and welfare.

Certificates of Stock

Section 22. Every holder of stock in the Company shall be entitled to have a certificate or certificates certifying the number of fully paid shares owned by him in the Company which shall be in form consistent with law and with the Charter of the Company and as shall be approved by the Board of Directors. The stock certificates shall be signed by: 1) either the Chairman of the Board of Directors or the President, and 2) either the Secretary or Treasurer. Such signatures may be facsimile or other similar method.

Section 23. All transfers of stock of the Company shall be made upon its books by authority of the holder of the shares or of his legal representative, and before a new certificate is issued the old certificate shall be surrendered for cancellation, provided that in case any certificate is lost, stolen or destroyed, a new certificate therefor may be issued pursuant to the provisions of Section 24 hereof.

Section 24. No certificate of shares of stock of the Company shall be issued in place of any certificate alleged to have been lost or stolen or destroyed, except upon the approval of the Board of Directors who may require delivery to the Company of a bond in such sum as it may direct and subject to its approval as indemnity against any claim in respect to such lost or stolen or destroyed certificate; provided that the Board of Directors may delegate to the Company's Transfer Agent and Registrar authority to issue and register, respectively, from time to time without further action or approval of the Board of Directors, new certificates of stock to replace certificates reported lost, stolen or destroyed upon receipt of an affidavit of loss and bond of indemnity in form and amount and with corporate surety satisfactory to them in each instance protecting the Company and them against loss. Such legal evidence of such loss or theft or destruction shall be furnished to the Board of Directors as may be required by them.

Section 25. The Board of Directors shall have power and authority to make all such rules and regulations as it may deem expedient concerning the issue, transfer, conversion and registration of certificates for shares of the capital stock of the Company, not inconsistent with the laws of North Carolina, the Charter of the Company and these By-Laws. The Board of Directors is authorized to appoint one or more transfer agents and registrars for the capital stock of the Company.

Section 26. The Board of Directors shall have power to close the stock transfer books or in lieu thereof to fix record dates as authorized by law.

General

Section 27. Subject to the provisions of the applicable statutes and the Charter of the Company, dividends, either cash or stock, upon the capital stock of the Company may be declared by the Board of Directors at any meeting thereof.

Section 28. Deeds, bonds, notes, mortgages and contracts of the Company may be executed on behalf of the Company by the President, or a Vice President, or any one of such other persons as shall from time to time be authorized by the Board of Directors, and when necessary or appropriate may be attested or countersigned by the Secretary or an Assistant Secretary, or the Treasurer or an Assistant Treasurer. The corporate seal of the Company may be affixed to deeds, bonds, notes, mortgages, contracts or stock certificates by an appropriate officer of the Company by impression thereon, or, by order of an appropriate officer of the Company, a facsimile of said seal may be affixed thereto by engraving, printing, lithograph or other method.

Section 29. The monies of the Company shall be deposited in the name of the Company in such bank or banks or trust company or trust companies as the Treasurer, with approval of the Chief Executive Officer, shall from time to time select, and shall be drawn out only by checks or other orders signed by persons designated by resolution by the Board of Directors.

Section 30. As and when used in any of the foregoing By-Laws the words "stockholder" and "stockholders" shall be deemed and held to be synonymous with the words "shareholder" and "shareholders", and the word "stock" shall be deemed and held to be synonymous with the words "share" or "shares", respectively, as used in Chapter 55 of the General Statutes of North Carolina.

Amendment of By-Laws

Section 31. The Board of Directors shall have power from time to time to adopt, amend, alter, add to, and repeal By-Laws for the Company by affirmative vote of a majority of the directors then holding office, provided, however, that the By-Laws may not be amended by the Board of Directors to require more than a majority of the voting shares for a quorum at a stockholder's meeting, or more than a majority vote at such meeting, except where higher percentages are required by law. Any By-Laws so made or any provisions thereof may be altered or repealed by vote of the holders of a majority of the total number of shares of the Company then issued and outstanding and entitled to vote thereon at any annual stockholders' meeting. Additionally, any By-Law adopted, amended or repealed by the stockholders may not be readopted, amended or repealed by the Board of Directors unless the Charter or a By-Law adopted by the stockholders authorizes the Board of Directors to adopt, amend or repeal that particular By-Law or the By-Laws generally.

Indemnity of Officers and Directors

Section 32. (a) The Company shall reimburse or indemnify any past, present or future officer or director of the Company for and against such liabilities and expenses as are authorized by (1) a resolution adopted by the Company's stockholders at a special meeting held on December 31, 1943, which is made a part hereof as though incorporated herein, or (2) by Sections 55-8-54, 55-8-55, 55-8-

56 and 55-8-57 of the General Statutes of North Carolina. Persons serving as officers or directors of the Company or serving in any such capacity at the request of the Company in any other corporation, partnership, joint venture, trust or other enterprise shall be provided reimbursement and indemnification by the Company to the maximum extent allowed hereunder or under applicable law, including without limitation Sections 55-8-54, 55-8-55, 55-8-56 and 55-8-57 of the General Statutes of North Carolina.

(b) In addition to the reimbursement and indemnification provisions set forth above, any person who at any time serves or has served (1) as an officer or director of the Company, or (2) at the request of the Company as an officer of director (or in any position of similar authority, by whatever title known) of any other corporation, partnership, joint venture, trust or other enterprise, or (3) as an individual trustee or administrator under any employee benefit plan, shall have a right to be indemnified by the Company to the fullest extent permitted by law against (i) all reasonable expenses, including attorney's fees, actually and necessarily incurred by him in connection with any pending, threatened or completed action, suit or proceeding, whether civil, criminal, administrative or investigative, and whether or not brought by the Company or on behalf of the Company in a derivative action, seeking to hold him liable by reason of or arising out of his status as such or his activities in any of the foregoing capacities, and (ii) payments made by him in satisfaction of any judgement, money decree, fine, penalty or settlement for which he may have become liable in any such action, suit or proceeding; provided, however, that the Company shall not indemnify any person against liability or litigation expense he may incur on account of his activities which were at the time taken known or believed by him to be clearly in conflict with the best interests of the Company.

(c) The Board of Directors shall take all action as may be necessary or appropriate to authorize the Company to pay all amounts required under these Sections 32(a),(b) and (c) of the By-Laws including, without limitation and to the extent deemed to be appropriate, necessary, or required by law (1) making a good faith evaluation of the manner in which the claimant for indemnity acted and of the reasonable amount of indemnity due such individual, or (2) making advances of costs and expenses, or (3) giving notice to, or obtaining approval by, the shareholders of the Company.

(d) Any person who serves or has served in any of the aforesaid capacities for or on behalf of the Company shall be deemed to be doing or to have done so in reliance upon, and as consideration for, the rights of reimbursement and indemnification provided for herein. Such rights of reimbursement and indemnification shall inure to the benefit of the legal representatives of such individuals, shall include amounts paid in settlement and shall not be exclusive of any other rights to which such individuals shall be entitled apart from the provisions of this Section.

(e) The Company may, in its sole discretion, wholly or partially indemnify and advance expenses to any employee or agent of the Company to the same extent as provided herein for officers and directors.

Dated: September 17, 2007

Exhibit No. 12(a)

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31

(dollars in millions)	**2007**	2006	2005	2004	2003
Earnings, as defined:					
Income from continuing operations before minority interest	**$ 702**	$ 523	$ 692	$ 654	$ 771
Fixed charges, as below	**625**	651	606	591	590
Preferred dividend requirements	**(7)**	(7)	(7)	(7)	(7)
Minority interest	**(9)**	(9)	29	19	–
Income taxes, as below	**329**	199	(42)	62	(138)
Total earnings, as defined	**$ 1,640**	$ 1,357	$ 1,278	$ 1,319	$ 1,216
Fixed Charges, as defined:					
Interest on long-term debt	**$ 553**	$ 619	$ 566	$ 529	$ 543
Other interest	**52**	13	21	43	27
Imputed interest factor in rentals – charged principally to operating expenses	**13**	12	12	12	13
Preferred dividend requirements of subsidiaries	**7**	7	7	7	7
Total fixed charges, as defined	**$ 625**	$ 651	$ 606	$ 591	$ 590
Income Taxes:					
Income tax expense (benefit)	**$ 334**	$ 204	$ (37)	$ 67	$ (130)
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(5)	(8)
Total income taxes	**$ 329**	$ 199	$ (42)	$ 62	$ (138)
Ratio of Earnings to Fixed Charges	**2.62**	2.08	2.11	2.23	2.06

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)	**2007**	2006	2005	2004	2003
Earnings, as defined:					
Income before cumulative effect of changes in accounting principles	**$ 501**	$ 457	$ 493	$ 461	$ 504
Fixed charges, as below	**223**	225	205	201	206
Income taxes, as below	**290**	260	234	234	233
Total earnings, as defined	**$ 1,014**	$ 942	$ 932	$ 896	$ 943
Fixed Charges, as defined:					
Interest on long-term debt	**$ 214**	$ 218	$ 191	$ 183	$ 188
Other interest	**1**	(1)	6	11	11
Imputed interest factor in rentals – charged principally to operating expenses	**8**	8	8	7	7
Total fixed charges, as defined	**223**	225	205	201	206
Preferred dividends, as defined	**5**	5	4	5	4
Total fixed charges and preferred dividends combined	**$ 228**	$ 230	$ 209	$ 206	$ 210
Income Taxes:					
Income tax expense	**$ 295**	$ 265	$ 239	$ 239	$ 241
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(5)	(8)
Total income taxes	**$ 290**	$ 260	$ 234	$ 234	$ 233
Ratio of Earnings to Fixed Charges	**4.55**	4.19	4.55	4.45	4.59
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.45**	4.10	4.46	4.36	4.50

Exhibit No. 12(c)

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)	**2007**	2006	2005	2004	2003
Earnings, as defined:					
Net income	**$ 317**	$ 328	$ 260	$ 335	$ 297
Fixed charges, as below	**188**	159	138	122	103
Income taxes	**144**	193	121	174	147
Total earnings, as defined	**$ 649**	$ 680	$ 519	$ 631	$ 547
Fixed Charges, as defined:					
Interest on long-term debt	**$ 157**	$ 145	$ 116	$ 107	$ 103
Other interest	**28**	10	18	10	(6)
Imputed interest factor in rentals – charged principally to operating expenses	**3**	4	4	5	6
Total fixed charges, as defined	**188**	159	138	122	103
Preferred dividends, as defined	**2**	2	2	2	2
Total fixed charges and preferred dividends combined	**$ 190**	$ 161	$ 140	$ 124	$ 105
Ratio of Earnings to Fixed Charges	**3.45**	4.28	3.76	5.17	5.31
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**3.42**	4.22	3.71	5.08	5.21

Exhibit No. 21

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, 2007. All other subsidiaries, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

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

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. 333−70332 on Form S−8, Post−Effective Amendment 1 to Registration Statement No. 333−47910 on Form S−3, Registration Statement No. 333−52328 on Form S−8, Registration Statement No. 333−78157 on Form S−4, 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, Registration Statement No. 333-104952 on Form S-8, Registration Statement No. 333-132879 on Form S-3, Registration Statement No. 333-132879-01 on Form S-3, Registration Statement No. 333-132879-02 on Form S-3 and Registration Statement No. 333-132879-03 on Form S-3 of our reports dated February 28, 2008 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 2007 and 2006) and the effectiveness of Progress Energy, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10−K of Progress Energy, Inc. for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

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 February 28, 2008, 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 2007 and 2006), appearing in this Annual Report on Form 10−K of PEC for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

Exhibit No. 23(c)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-148040 and 333-126967, each on Form S-3 of our reports dated February 28, 2008, 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 2007 and 2006) appearing in this Annual Report on Form 10−K of PEF for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

Exhibit 31(a)

CERTIFICATION

I, William D. Johnson, certify that:

1. I have reviewed this annual report on Form 10-K of Progress Energy, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008

/s/ William D. Johnson

William D. Johnson

Chairman, President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this annual report on Form 10-K of Progress Energy, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008 /s/ Peter M. Scott III

Peter M. Scott III

Executive Vice President and Chief Financial Officer

Exhibit 31(c)

CERTIFICATION

I, Lloyd M. Yates, certify that:

1. I have reviewed this annual report on Form 10-K of Carolina Power & Light Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008 /s/ Lloyd M. Yates

Lloyd M. Yates

President and Chief Executive Officer

Exhibit 31(d)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this annual report on Form 10-K of Carolina Power & Light Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008 /s/ Peter M. Scott III

Peter M. Scott III

Executive Vice President and Chief Financial Officer

Exhibit 31(e)

CERTIFICATION

I, Jeffrey J. Lyash, certify that:

1. I have reviewed this annual report on Form 10-K of Florida Power Corporation;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008 /s/ Jeffrey J. Lyash

Jeffrey J. Lyash

President and Chief Executive Officer

Exhibit 31(f)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this annual report on Form 10-K of Florida Power Corporation;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: February 26, 2008 /s/ Peter M. Scott III

Peter M. Scott III

Executive Vice President and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Progress Energy, Inc. (the “Company”) for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, William D. Johnson, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(b)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Progress Energy, Inc. (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(c)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Carolina Power & Light Company (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Lloyd M. Yates, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(d)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Carolina Power & Light Company (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(e)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Florida Power Corporation (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jeffrey J. Lyash, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(f)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Florida Power Corporation (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer
February 26, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

APPENDIX C PROGRESS ENERGY, INC., FORM 10-Q, QUARTERLY PERIOD ENDED MARCH 31, 2008

Form 10-Q

PROGRESS ENERGY INC - PGN

Filed: May 12, 2008 (period: March 31, 2008)

Quarterly report which provides a continuing view of a company's financial position

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

FORM 10-Q

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

For the quarterly period ended March 31, 2008

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, states of incorporation, addresses of principal executive offices, and telephone numbers	I.R.S. Employer Identification Number
1-15929	**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.** 299 First Avenue North St. Petersburg, Florida 33701 Telephone: (727) 820-5151 State of Incorporation: Florida	59-0247770

NONE
(Former name, former address and former fiscal year, if changed since last report)

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.

Progress Energy, Inc. (Progress Energy)	Yes	☒	No	☐
Carolina Power & Light Company (PEC)	Yes	☒	No	☐

Florida Power Corporation (PEF)	Yes	☐	No	☒

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

Progress Energy	Large accelerated filer	☒	Accelerated filer	☐
	Non-accelerated filer	☐	Smaller reporting company	☐
PEC	Large accelerated filer	☐	Accelerated filer	☐
	Non-accelerated filer	☒	Smaller reporting company	☐
PEF	Large accelerated filer	☐	Accelerated filer	☐
	Non-accelerated filer	☒	Smaller reporting company	☐

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

Progress Energy	Yes	☐	No	☒
PEC	Yes	☐	No	☒
PEF	Yes	☐	No	☒

As of May 5, 2008, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	261,320,773
PEC	Common Stock (Without Par Value)	159,608,055 (all of which were held directly by Progress Energy, Inc.)
PEF	Common Stock (Without Par Value)	100 (all of which were held indirectly by Progress Energy, Inc.)

This combined Form 10-Q 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 H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format.

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PART II. OTHER INFORMATION

GLOSSARY OF TERMS

We use the words "Progress Energy," "we," "us" or "our" with respect to certain information to indicate that such information relates to Progress Energy, Inc. and its subsidiaries on a consolidated basis. When appropriate, the parent holding company or the subsidiaries of Progress Energy are specifically identified on an unconsolidated basis as we discuss their various business activities.

The following abbreviations or acronyms are used by the Progress Registrants:

TERM	DEFINITION
2007 Form 10-K	Progress Registrants' annual report on Form 10-K for the fiscal year ended December 31, 2007
401(k)	Progress Energy 401(k) Savings & Stock Ownership Plan
AFUDC	Allowance for funds used during construction
AHI	Affordable housing investment
ARO	Asset retirement obligation
Annual Average Price	Average wellhead price per barrel for unregulated domestic crude oil for the year
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Broad River	Broad River LLC's Broad River Facility
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCO	Competitive Commercial Operations
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Ceredo	Ceredo Synfuel LLC
CIGFUR	Carolina Industrial Group for Fair Utility Rates II
Clean Smokestacks Act	North Carolina Clean Smokestacks Act, enacted in June 2002
Coal Mining	The remaining operations of Progress Fuels subsidiaries engaged in the coal mining business
Coal and Synthetic Fuels	Former business segment that had been primarily engaged in the production and sales of coal-based solid synthetic fuels, the operation of synthetic fuels facilities for third parties and coal terminal services
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Colona	Colona Synfuel Limited Partnership, LLLP

Corporate and Other	Corporate and Other segment includes Corporate as well as other nonregulated businesses
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's Crystal River Units No. 4 and 5 coal-fired steam turbines
CUCA	Carolina Utility Customers Association
CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DeSoto	DeSoto County Generating Co., LLC
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"
Dixie Fuels	Dixie Fuels Limited
DOE	United States Department of Energy

DSM	Demand-side management
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three are wholly owned
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause
EIA	Energy Information Agency
EIP	Equity Incentive Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement and construction contract
ERO	Electric reliability organization
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FDCA	Florida Department of Community Affairs
FGT	Florida Gas Transmission Company
FIN 39	FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts"
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN 46R	FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143"
FIN 48	FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"
the Florida Global Case	U.S. Global, LLC v. Progress Energy, Inc. et al
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FSP	FASB Staff Position
FSP FIN 39-1	FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts"
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 business

the Georgia Contracts	Full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO
Georgia Power	Georgia Power Company, a subsidiary of Southern Company
Georgia Operations	Former reporting unit consisting of the Effingham, Monroe, Walton and Washington nonregulated generation plants in service and the Georgia Contracts
Global	U.S. Global, LLC
GridSouth	GridSouth Transco, LLC
Gulfstream	Gulfstream Gas System, L.L.C.
Harris	PEC's Shearon Harris Nuclear Plant
IBEW	International Brotherhood of Electrical Workers
IRS	Internal Revenue Service
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Level 3 Communications	Level 3 Communications, Inc.
LIBOR	London Inter Bank Offering Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in Part I, Item 2 of this Form 10-Q
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured gas plant
MW	Megawatts
MWh	Megawatt-hours
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NCDWQ	North Carolina Division of Water Quality
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
North Carolina Global Case	Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC
the Notes Guarantee	Florida Progress' full and unconditional guarantee of the Subordinated Notes
NOx	Nitrogen Oxides
NOx SIP Call	EPA rule which requires 22 states including North Carolina, South Carolina and Georgia (but excluding Florida) to further reduce emissions of nitrogen oxides
NSR	New Source Review requirements by the EPA
NRC	United States Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff

OCI	Other comprehensive income
OPC	Florida's Office of Public Counsel
OPEB	Postretirement benefits other than pensions
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
PEF	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
PESC	Progress Energy Service Company, LLC
the Phase-out Price	Price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits are fully eliminated
PM 2.5	EPA standard for particulate matter less than 2.5 microns in diameter
PM 2.5-10	EPA standard for particulate matter between 2.5 and 10 microns in diameter
PM 10	EPA standard for particulate matter less than 10 microns in diameter
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 Affiliates	Five affiliated coal-based solid synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The 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
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PT LLC	Progress Telecom, LLC
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
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
QF	Qualifying facility
RCA	Revolving credit agreement

REC	Renewable energy certificates
REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
Rowan	Rowan County Power, LLC
RSA	Restricted stock awards program
RSU	Restricted stock unit
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
Section 29	Section 29 of the Code
Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 316(b)	Section 316(b) of the Clean Water Act
Section 45K	Section 45K of the Code
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART I, Item 1 of this Form 10-Q
SERC	SERC Reliability Corporation
SESH	Southeast Supply Header, L.L.C.
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. 123R	Statement of Financial Accounting Standards No. 123R, "Share-Based Payment"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS No. 141R	Statement of Financial Accounting Standards No. 141R, "Business Combinations"

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. 157	Statement of Financial Accounting Standards No. 157, “Fair Value Measurements”
SFAS No. 158	Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”
SFAS No. 159	Statement of Financial Accounting Standards No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115”
SFAS No. 160	Statement of Financial Accounting Standards No. 160, “Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51”
SFAS No. 161	Statement of Financial Accounting Standards No. 161, “Disclosures About Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133”
SNG	Southern Natural Gas Company

SO_2	Sulfur dioxide
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
Terminals	Coal terminals and docks in West Virginia and Kentucky
the Threshold Price	Price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits begin to be reduced
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
Winchester Production	Winchester Production Company, Ltd.

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-Q 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. 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.

In addition, examples of forward-looking statements discussed in this Form 10-Q include, but are not limited to, statements made in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) including, but not limited to, statements under the sub-heading “Results of Operations” about trends and uncertainties, “Liquidity and Capital Resources” about operating cash flows, future liquidity requirements and estimated capital expenditures and “Other Matters” about our synthetic fuels tax credits, changes in the regulatory environment, meeting increasing energy demand in our service territories and the impact of environmental regulations.

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 Energy Policy Act of 2005 (EPACT); the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the impact on our facilities and businesses from a terrorist attack; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; the Progress Registrants’ ability to control costs, including operation and maintenance expense (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the ability to successfully access capital markets on favorable terms; the impact that increases in leverage may have on each of the Progress Registrants; 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; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); the investment performance of our nuclear decommissioning trust funds and the assets of our pension and benefit plans; 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 the Risk Factors section in the Progress Registrants’ annual report on Form 10-K for the fiscal year ended December 31, 2007 (2007 Form 10-K), which was filed with the SEC on February 28, 2008, and is updated for material changes, if any, in this Form 10-Q and in our other SEC filings. 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 management assess the effect of each such factor on the Progress Registrants.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PROGRESS ENERGY, INC.
UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
March 31, 2008

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data)

Three months ended March 31	2008	2007
Operating revenues	**$ 2,066**	$ 2,072
Operating expenses		
Fuel used in electric generation	**697**	736
Purchased power	**232**	221
Operation and maintenance	**443**	420
Depreciation and amortization	**206**	219
Taxes other than on income	**121**	124
Other	**2**	1
Total operating expenses	**1,701**	1,721
Operating income	**365**	351
Other income		
Interest income	**7**	8
Other, net	**18**	11
Total other income	**25**	19
Interest charges		
Interest charges	**161**	145
Allowance for borrowed funds used during construction	**(8)**	(3)
Total interest charges, net	**153**	142
Income from continuing operations before income tax and minority interest	**237**	228
Income tax expense	**84**	72
Income from continuing operations before minority interest	**153**	156
Minority interest in subsidiaries' income, net of tax	**(4)**	(7)
Income from continuing operations	**149**	149
Discontinued operations, net of tax	**60**	126
Net income	**$ 209**	$ 275
Average common shares outstanding – basic	**259**	254
Basic earnings per common share		
Income from continuing operations	**$ 0.58**	$ 0.59
Discontinued operations, net of tax	**0.23**	0.49
Net income	**$ 0.81**	$ 1.08
Diluted earnings per common share		
Income from continuing operations	**$ 0.58**	$ 0.59
Discontinued operations, net of tax	**0.23**	0.49
Net income	**$ 0.81**	$ 1.08
Dividends declared per common share	**$ 0.615**	$ 0.610

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

PROGRESS ENERGY, INC.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	**March 31, 2008**	December 31, 2007
ASSETS		
Utility plant		
Utility plant in service	**$ 25,490**	$ 25,327
Accumulated depreciation	**(11,037)**	(10,895)
Utility plant in service, net	**14,453**	14,432
Held for future use	**37**	37
Construction work in progress	**2,124**	1,765
Nuclear fuel, net of amortization	**372**	371
Total utility plant, net	**16,986**	16,605
Current assets		
Cash and cash equivalents	**400**	255
Short-term investments	**1**	1
Receivables, net	**767**	1,167
Inventory	**999**	994
Deferred fuel cost	**138**	154
Deferred income taxes	**3**	27
Derivative assets	**217**	85
Assets to be divested	**–**	52
Prepayments and other current assets	**73**	94
Total current assets	**2,598**	2,829
Deferred debits and other assets		
Regulatory assets	**926**	946
Nuclear decommissioning trust funds	**1,313**	1,384
Miscellaneous other property and investments	**466**	448
Goodwill	**3,655**	3,655
Derivative assets	**210**	119
Other assets and deferred debits	**390**	379
Total deferred debits and other assets	**6,960**	6,931
Total assets	**$ 26,544**	$ 26,365
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 261 million and 260 million shares issued and outstanding, respectively	**$ 6,071**	$ 6,028
Unearned ESOP shares (1 million and 2 million shares, respectively)	**(25)**	(37)
Accumulated other comprehensive loss	**(42)**	(34)
Retained earnings	**2,514**	2,465
Total common stock equity	**8,518**	8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93
Minority interest	**6**	84
Long-term debt, affiliate	**271**	271
Long-term debt, net	**8,391**	8,466
Total capitalization	**17,279**	17,336
Current liabilities		
Current portion of long-term debt	**1,197**	877
Short-term debt	**205**	201
Accounts payable	**794**	819
Interest accrued	**128**	173
Dividends declared	**161**	160
Customer deposits	**262**	255
Regulatory liabilities	**145**	173
Liabilities to be divested	**–**	8
Income taxes accrued	**66**	8
Other current liabilities	**428**	628
Total current liabilities	**3,386**	3,302

Deferred credits and other liabilities		
Noncurrent income tax liabilities	**288**	361
Accumulated deferred investment tax credits	**136**	139
Regulatory liabilities	**2,775**	2,554
Asset retirement obligations	**1,397**	1,378
Accrued pension and other benefits	**761**	763
Capital lease obligations	**239**	239
Other liabilities and deferred credits	**283**	293
Total deferred credits and other liabilities	**5,879**	5,727
Commitments and contingencies (Notes 12 and 13)		
Total capitalization and liabilities	**$ 26,544**	$ 26,365

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

PROGRESS ENERGY, INC.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)

Three months ended March 31		2008		2007
Operating activities				
Net income	**$**	**209**	$	275
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation and amortization		**235**		250
Deferred income taxes and investment tax credits, net		**5**		120
Deferred fuel cost		**24**		108
Other adjustments to net income		**(47)**		(7)
Cash provided (used) by changes in operating assets and liabilities				
Receivables		**390**		59
Inventory		**4**		(34)
Prepayments and other current assets		**14**		(64)
Income taxes, net		**60**		(237)
Accounts payable		**79**		(52)
Other current liabilities		**(171)**		(4)
Other assets and deferred debits		**(38)**		(83)
Other liabilities and deferred credits		**13**		(15)
Net cash provided by operating activities		**777**		316
Investing activities				
Gross property additions		**(618)**		(471)
Nuclear fuel additions		**(41)**		(61)
Proceeds from sales of discontinued operations and other assets, net of cash divested		**95**		30
Purchases of available-for-sale securities and other investments		**(488)**		(192)
Proceeds from sales of available-for-sale securities and other investments		**473**		252
Other investing activities		**(6)**		–
Net cash used by investing activities		**(585)**		(442)
Financing activities				
Issuance of common stock		**20**		65
Dividends paid on common stock		**(159)**		(155)
Payments of short-term debt with original maturities greater than 90 days		**(176)**		–
Net increase in short-term debt		**180**		117
Proceeds from issuance of long-term debt, net		**322**		–
Retirement of long-term debt		**(80)**		–
Cash distributions to minority interests of consolidated subsidiaries		**(85)**		–
Other financing activities		**(69)**		(33)
Net cash used by financing activities		**(47)**		(6)
Net increase (decrease) in cash and cash equivalents		**145**		(132)
Cash and cash equivalents at beginning of period		**255**		265
Cash and cash equivalents at end of period	**$**	**400**	$	133
Supplemental disclosures				
Significant noncash transactions				
Note receivable for disposal of ownership interest in Ceredo	**$**	**–**	$	48
Noncash property additions accrued for as of March 31		**276**		158

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
March 31, 2008

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of INCOME

(in millions)

Three months ended March 31	2008	2007
Operating revenues	**$ 1,068**	$ 1,058
Operating expenses		
Fuel used in electric generation	**356**	351
Purchased power	**49**	58
Operation and maintenance	**248**	248
Depreciation and amortization	**126**	117
Taxes other than on income	**50**	50
Other	**(1)**	(1)
Total operating expenses	**828**	823
Operating income	**240**	235
Other income		
Interest income	**5**	6
Other, net	**4**	3
Total other income	**9**	9
Interest charges		
Interest charges	**58**	57
Allowance for borrowed funds used during construction	**(2)**	(1)
Total interest charges, net	**56**	56
Income before income tax	**193**	188
Income tax expense	**70**	64
Net income	**123**	124
Preferred stock dividend requirement	**1**	1
Earnings for common stock	**$ 122**	$ 123

See Notes to PEC Unaudited Condensed Consolidated Interim Financial Statements.

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

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	**March 31, 2008**	December 31, 2007
ASSETS		
Utility plant		
Utility plant in service	**$ 15,176**	$ 15,117
Accumulated depreciation	**(7,161)**	(7,097)
Utility plant in service, net	**8,015**	8,020
Held for future use	**2**	2
Construction work in progress	**625**	566
Nuclear fuel, net of amortization	**298**	292
Total utility plant, net	**8,940**	8,880
Current assets		
Cash and cash equivalents	**297**	25
Short-term investments	**1**	1
Receivables, net	**451**	491
Receivables from affiliated companies	**29**	42
Notes receivable from affiliated companies	**85**	–
Inventory	**507**	510
Deferred fuel cost	**133**	148
Prepayments and other current assets	**32**	49
Total current assets	**1,535**	1,266
Deferred debits and other assets		
Regulatory assets	**653**	680
Nuclear decommissioning trust funds	**771**	804
Miscellaneous other property and investments	**197**	192
Other assets and deferred debits	**191**	160
Total deferred debits and other assets	**1,812**	1,836
Total assets	**$ 12,287**	$ 11,982
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	**$ 2,072**	$ 2,054
Unearned ESOP common stock	**(25)**	(37)
Accumulated other comprehensive loss	**(15)**	(10)
Retained earnings	**1,894**	1,772
Total common stock equity	**3,926**	3,779
Preferred stock – not subject to mandatory redemption	**59**	59
Long-term debt, net	**3,107**	3,183
Total capitalization	**7,092**	7,021
Current liabilities		
Current portion of long-term debt	**700**	300
Notes payable to affiliated companies	–	154
Accounts payable	**287**	308
Payables to affiliated companies	**58**	71
Interest accrued	**51**	58
Customer deposits	**73**	70
Income taxes accrued	**69**	27
Other current liabilities	**153**	182
Total current liabilities	**1,391**	1,170
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**936**	936
Accumulated deferred investment tax credits	**120**	122
Regulatory liabilities	**1,106**	1,098
Asset retirement obligations	**1,078**	1,063
Accrued pension and other benefits	**457**	459

Other liabilities and deferred credits	**107**	113
Total deferred credits and other liabilities	**3,804**	3,791
Commitments and contingencies (Notes 12 and 13)		
Total capitalization and liabilities	**$ 12,287**	$ 11,982

See Notes to PEC Unaudited Condensed Consolidated Interim Financial Statements.

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)

Three months ended March 31	**2008**	2007
Operating activities		
Net income	**$ 123**	$ 124
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**151**	138
Deferred income taxes and investment tax credits, net	**6**	7
Deferred fuel cost	**42**	44
Other adjustments to net income	**13**	(11)
Cash provided (used) by changes in operating assets and liabilities		
Receivables	**38**	25
Receivables from affiliated companies	**13**	7
Inventory	**8**	(8)
Prepayments and other current assets	**17**	3
Income taxes, net	**50**	(3)
Accounts payable	**22**	(17)
Payables to affiliated companies	**(13)**	(66)
Other current liabilities	**(28)**	(25)
Other assets and deferred debits	**(19)**	(8)
Other liabilities and deferred credits	**(4)**	–
Net cash provided by operating activities	**419**	210
Investing activities		
Gross property additions	**(173)**	(208)
Nuclear fuel additions	**(41)**	(38)
Purchases of available-for-sale securities and other investments	**(193)**	(120)
Proceeds from sales of available-for-sale securities and other investments	**185**	162
Changes in advances to affiliated companies	**(85)**	24
Other investing activities	**(4)**	6
Net cash used by investing activities	**(311)**	(174)
Financing activities		
Dividends paid on preferred stock	**(1)**	(1)
Dividends paid to parent	**–**	(36)
Proceeds from issuance of long-term debt, net	**322**	–
Changes in advances from affiliated companies	**(154)**	–
Other financing activities	**(3)**	11
Net cash provided (used) by financing activities	**164**	(26)
Net increase in cash and cash equivalents	**272**	10
Cash and cash equivalents at beginning of period	**25**	71
Cash and cash equivalents at end of period	**$ 297**	$ 81
Supplemental disclosures		
Significant noncash transactions		
Noncash property additions accrued for as of March 31	**$ 76**	$ 83

See Notes to PEC Unaudited Condensed Consolidated Interim Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
UNAUDITED CONDENSED INTERIM FINANCIAL STATEMENTS
March 31, 2008

UNAUDITED CONDENSED STATEMENTS of INCOME

(in millions)

Three months ended March 31	2008	2007
Operating revenues	**$ 996**	$ 1,011
Operating expenses		
Fuel used in electric generation	**341**	385
Purchased power	**183**	163
Operation and maintenance	**203**	175
Depreciation and amortization	**76**	97
Taxes other than on income	**71**	74
Total operating expenses	**874**	894
Operating income	**122**	117
Other income		
Interest income	**1**	1
Other, net	**17**	7
Total other income	**18**	8
Interest charges		
Interest charges	**50**	39
Allowance for borrowed funds used during construction	**(6)**	(2)
Total interest charges, net	**44**	37
Income before income tax	**96**	88
Income tax expense	**29**	27
Net income	**67**	61
Preferred stock dividend requirement	**1**	1
Earnings for common stock	**$ 66**	$ 60

See Notes to PEF Unaudited Condensed Interim Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.

UNAUDITED CONDENSED BALANCE SHEETS

(in millions)	March 31, 2008	December 31, 2007
ASSETS		
Utility plant		
Utility plant in service	**$ 10,129**	$ 10,025
Accumulated depreciation	**(3,816)**	(3,738)
Utility plant in service, net	**6,313**	6,287
Held for future use	**35**	35
Construction work in progress	**1,499**	1,199
Nuclear fuel, net of amortization	**74**	79
Total utility plant, net	**7,921**	7,600
Current assets		
Cash and cash equivalents	**16**	23
Receivables, net	**307**	351
Receivables from affiliated companies	**15**	8
Notes receivable from affiliated companies	**–**	149
Inventory	**493**	484
Deferred income taxes	**–**	39
Income taxes receivable	**–**	41
Derivative assets	**204**	83
Prepayments and other current assets	**11**	9
Total current assets	**1,046**	1,187
Deferred debits and other assets		
Regulatory assets	**273**	266
Nuclear decommissioning trust funds	**542**	580
Miscellaneous other property and investments	**44**	46
Derivative assets	**174**	100
Prepaid pension cost	**227**	221
Other assets and deferred debits	**80**	63
Total deferred debits and other assets	**1,340**	1,276
Total assets	**$ 10,307**	$ 10,063
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$ 1,110**	$ 1,109
Accumulated other comprehensive loss	**(12)**	(8)
Retained earnings	**1,967**	1,901
Total common stock equity	**3,065**	3,002
Preferred stock – not subject to mandatory redemption	**34**	34
Long-term debt, net	**2,687**	2,686
Total capitalization	**5,786**	5,722
Current liabilities		
Current portion of long-term debt	**452**	532
Notes payable to affiliated companies	**95**	–
Accounts payable	**485**	473
Payables to affiliated companies	**54**	87
Interest accrued	**35**	57
Customer deposits	**189**	185
Derivative liabilities	**11**	38
Regulatory liabilities	**145**	173
Other current liabilities	**189**	92
Total current liabilities	**1,655**	1,637
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**354**	401
Accumulated deferred investment tax credits	**16**	17

Regulatory liabilities		**1,544**		1,330
Asset retirement obligations		**319**		315
Accrued pension and other benefits		**304**		304
Capital lease obligations		**223**		224
Other liabilities and deferred credits		**106**		113
Total deferred credits and other liabilities		**2,866**		2,704
Commitments and contingencies (Notes 12 and 13)				
Total capitalization and liabilities	**$**	**10,307**	$	10,063

See Notes to PEF Unaudited Condensed Interim Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.

UNAUDITED CONDENSED STATEMENTS of CASH FLOWS

(in millions)

Three months ended March 31	**2008**	2007
Operating activities		
Net income	**$ 67**	$ 61
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**80**	103
Deferred income taxes and investment tax credits, net	**15**	14
Deferred fuel (credit) cost	**(18)**	64
Other adjustments to net income	**(13)**	–
Cash provided (used) by changes in operating assets and liabilities		
Receivables	**40**	41
Receivables from affiliated companies	**(7)**	2
Inventory	**(8)**	(23)
Prepayments and other current assets	**(3)**	56
Income taxes, net	**43**	36
Accounts payable	**70**	18
Payables to affiliated companies	**(33)**	(71)
Other current liabilities	**35**	12
Other assets and deferred debits	**(17)**	6
Other liabilities and deferred credits	**19**	(10)
Net cash provided by operating activities	**270**	309
Investing activities		
Gross property additions	**(446)**	(261)
Nuclear fuel additions	**–**	(23)
Purchases of available-for-sale securities and other investments	**(247)**	(44)
Proceeds from sales of available-for-sale securities and other investments	**247**	44
Changes in advances to affiliated companies	**149**	–
Proceeds from sales of assets to affiliated companies	**8**	–
Other investing activities	**(2)**	–
Net cash used by investing activities	**(291)**	(284)
Financing activities		
Dividends paid on preferred stock	**(1)**	(1)
Retirement of long-term debt	**(80)**	–
Changes in advances from affiliated companies	**95**	(36)
Other financing activities	**–**	1
Net cash provided (used) by financing activities	**14**	(36)
Net decrease in cash and cash equivalents	**(7)**	(11)
Cash and cash equivalents at beginning of period	**23**	23
Cash and cash equivalents at end of period	**$ 16**	$ 12
Supplemental disclosures		
Significant noncash transactions		
Noncash property additions accrued for as of March 31	**$ 198**	$ 75

See Notes to PEF Unaudited Condensed Interim Financial Statements.

INDEX TO APPLICABLE COMBINED NOTES TO UNAUDITED CONDENSED INTERIM FINANCIAL STATEMENTS BY REGISTRANT

Each of the following combined notes to the unaudited condensed interim 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. The notes that are not listed below for PEC or PEF are not, and shall not be deemed to be, part of PEC's or PEF's financial statements contained herein.

Registrant	**Applicable Notes**
PEC	1, 2, 4 through 9, and 11 through 13
PEF	1, 2, 4 through 9, and 11 through 13

COMBINED NOTES TO UNAUDITED CONDENSED INTERIM 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 Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (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. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. See Note 10 for further information about our segments.

PEC

PEC is a regulated public utility 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), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility 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 and the FERC.

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for annual financial statements. The December 31, 2007 condensed balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. Because the accompanying interim financial statements do not include all of the information and footnotes required by GAAP for annual financial statements, they should be read in conjunction with the audited financial statements and notes thereto included in the Progress Registrants' annual report on Form 10-K for the fiscal year ended December 31, 2007 (2007 Form 10-K).

In accordance with the provisions of Accounting Principles Board Opinion No. 28, "Interim Financial Reporting," GAAP requires companies to apply a levelized effective tax rate to interim periods that is consistent with the estimated annual effective tax rate. The tax levelization expense or benefit recorded during the interim period, which will have no impact on total year net income, maintains an effective tax rate consistent with the estimated annual effective tax rate. The fluctuations in the effective tax rate for the three months ended March 31, 2008, are primarily due to seasonal fluctuations in energy sales and earnings from the Utilities. The fluctuations in the effective tax rate for the three months ended March 31, 2007, are primarily due to the recognition of synthetic fuels tax credits and seasonal fluctuations in energy sales and earnings from the Utilities. Total tax levelization adjustments increased (decreased) income tax expense for the Progress Registrants for the three months ended March 31, 2008 and 2007, as follows:

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Progress Energy	**$ (1)**	$ (8)
PEC	**(3)**	(1)
PEF	**1**	–

For the three months ended March 31, 2007, $10 million of the net $8 million tax levelization benefit was related to synthetic fuels tax credits recorded by the synthetic fuels businesses and is included in discontinued operations on the Consolidated Statements of Income, pursuant to the intraperiod tax allocation rules as set forth in Statement of Financial Accounting Standard (SFAS) No. 109, “Accounting for Income Taxes” (SFAS No. 109). When the synthetic fuels businesses were reclassified to discontinued operations in the fourth quarter of 2007 (See Note 3A), the impacts of the quarterly tax levelization adjustments associated with the synthetic fuels tax credits were not also reclassified to discontinued operations, including the $10 million levelization benefit for the three months ended March 31, 2007 discussed above. Consequently, the presentation of the unaudited summarized quarterly financial data previously reported for Progress Energy in Note 24 in the 2007 Form 10-K was not correct. As a result, the unaudited summarized quarterly financial data has been restated. This correction does not affect our Consolidated Statements of Income for 2007 or 2006, as the quarterly tax levelization adjustments net to zero on an annual basis. The following table presents specific line item amounts for the three months ended March 31, 2007, included in Note 24 in the 2007 Form 10-K that have been restated as a result of this correction:

Progress Energy

(in millions except per share data)	As originally reported	As restated
Income from continuing operations	$ 159	$ 149
Common stock data		
Basic earnings per common share		
Income from continuing operations	0.63	0.59
Diluted earnings per common share		
Income from continuing operations	0.62	0.59

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

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Progress Energy	**$ 65**	$ 66
PEC	**25**	24
PEF	**40**	42

The amounts included in these financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary to fairly present the Progress Registrants’ financial position and results of operations for the interim periods. Unless otherwise noted, all adjustments are normal and recurring in nature. Due to seasonal weather variations and the timing of outages of electric generating units, especially nuclear-fueled units, the results of operations for interim periods are not necessarily indicative of amounts expected for the entire year or future periods.

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

Certain amounts for 2007 have been reclassified to conform to the 2008 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 46R).

PROGRESS ENERGY

In March 2007, we disposed of our 100 percent ownership interest in Ceredo Synfuel LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualifies for federal tax credits under Section 45K of the Internal Revenue Code (the Code), to a third-party buyer. Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and continues to consolidate Ceredo. See Note 3F for additional information on the disposal of Ceredo.

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several 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 March 31, 2008, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $6 million, which represents our net remaining investment in the 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 March 31, 2008, the assets of the two entities totaled $37 million, the majority of which are collateral for the entities' obligations, and were included in miscellaneous other property and investments in the Consolidated Balance Sheets.

PEC has an interest in and consolidates one limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC has requested the necessary information to determine if the 17 partnerships and the power plant owner 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 accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparties, 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 21 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At March 31, 2008, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements was $18 million, which primarily represents its 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 four variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one limited liability corporation, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At March 31, 2008, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $56 million. The majority of this exposure is related to a prepayment clause in the building lease of which $2 million had been prepaid at March 31, 2008. 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.

2. NEW ACCOUNTING STANDARDS

Fair Value Measurements - Adoption of FASB Statements Nos. 157 and 159

Refer to Note 7 for information regarding our first quarter 2008 implementation of FASB Statement of Financial Accounting Standards SFAS No. 157, "Fair Value Measurements" (SFAS No. 157).

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied on an instrument by instrument basis, is irrevocable (unless a new election date occurs) and is applied to the entire financial instrument. SFAS No. 159 was effective for us and the Utilities on January 1, 2008. We and the utilities did not elect to adopt the fair value option for any financial instruments.

FASB Staff Position No. 39-1, An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts

FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" (FIN 39), specifies what conditions must be met for an entity to have the right to offset assets and liabilities in the balance sheet and clarifies when it is appropriate to offset amounts recognized for forward, interest rate swap, currency swap, option, and other conditional or exchange contracts. FIN 39 also permits offsetting of fair value amounts recognized for multiple contracts executed with the same counterparty under a master netting arrangement. On April 30, 2007, the FASB issued FASB Staff Position (FSP) No. FIN 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), which amended portions of FIN 39 to make certain terms consistent with those used in SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133). FSP FIN 39-1 also amends FIN 39 to allow for the offsetting of fair value amounts for the right to reclaim collateral assets or liabilities arising from the same master netting arrangement as the derivative instruments. We implemented the FSP as of January 1, 2008, as a retrospective change in accounting principle for all financial statements presented. We and the Utilities previously offset fair value amounts recognized for derivative instruments under master netting arrangements. As allowed under FSP FIN 39-1, we and the Utilities changed our accounting policy effective January 1, 2008, and discontinued the offset of fair value amounts for such derivatives. The change had no impact on our or the Utilities' results of operations or equity and resulted in increases in previously-reported December 31, 2007 assets and liabilities, as follows:

(in millions)	**Progress Energy**	**PEC**	**PEF**
Current assets	$ 54	$ 19	$ 35
Noncurrent assets	25	1	24
Current liabilities	54	19	35
Noncurrent liabilities	25	1	24

FASB Statement No. 161, Disclosures About Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133

In March 2008, the FASB issued SFAS No. 161, "Disclosures About Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133" (SFAS No. 161), which requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS No. 161 requires significant quantitative disclosures to be presented in a tabular format, including disclosures of the location, by line item, of fair value amounts of derivative instruments in the balance sheet and the location, by line item, of amounts of derivative gains and losses reported in the income statement. SFAS No. 161 also requires entities to disclose information regarding the existence and nature of credit-risk-related contingent features included in derivative instruments that require the instrument to be settled or collateral posted in the event of a credit downgrade. SFAS No. 161 is effective for us and the Utilities on January 1, 2009. The adoption of SFAS No. 161 will change certain disclosures in the notes to the financial statments, but will have no impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale were used for general corporate purposes. As a result, during the three months ended March 31, 2008, we recorded an after-tax gain of $46 million on the sale of these assets. The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Terminals as discontinued operations.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Internal Revenue Code (the Code). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels were generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007. In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), operations must be abandoned prior to reporting them as discontinued operations. The accompanying consolidated income statements have been restated for all periods presented to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

In addition, as discussed in Note 1B, the recognition of tax credits generated by the production and sale of synthetic fuels historically resulted in significant fluctuations in our effective tax rate for interim periods. Pursuant to the intraperiod tax allocation rules of SFAS No. 109, $10 million of tax levelization benefit, which is primarily related to the recognition of synthetic fuels tax credits, is included in the discontinued operations income tax benefit for the three months ended March 31, 2007.

Results of discontinued operations for the three months ended March 31 for Terminals and the synthetic fuels businesses were as follows:

(in millions)	**2008**	2007
Revenues	**$ 17**	$ 262
Earnings before income taxes and minority interest	**10**	15
Income tax benefit	**3**	53
Minority interest portion of synthetic fuel (earnings) losses	**(1)**	3
Net earnings from discontinued operations	**12**	71
Gain on disposal of discontinued operations, including income tax expense of $7	**46**	–
Earnings from discontinued operations	**$ 58**	$ 71

B. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 megawatts (MW) of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated loss of $226 million in December 2006. Based on the terms of the final agreement, during the quarter ended March 31, 2007, we reversed $16 million after-tax of the impairment recorded in 2006.

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represents substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represents the net cost to assign the Georgia Contracts and other related contracts. In the quarter ended June 30, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax. We used the net proceeds from these transactions for general corporate purposes.

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the three months ended March 31, 2007, was $8 million. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. Results of CCO discontinued operations for the three months ended March 31 were as follows:

(in millions)	2007
Revenues	$ 252
Earnings before income taxes	70
Income tax expense	(27)
Net earnings from discontinued operations	43
Reversal of estimated loss on disposal of discontinued operations, including income tax benefit of $2	16
Earnings from discontinued operations	$ 59

C. COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of approximately 30,000 acres in Lee County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. As a result of the sale, during the three months ended March 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets.

The accompanying consolidated financial statements reflect Coal Mining as discontinued operations. We ceased recording depreciation expense upon classification of Coal Mining as discontinued operations in November 2005. Results of Coal Mining discontinued operations for the three months ended March 31 were as follows:

(in millions)	**2008**	2007
Revenues	**$ 2**	$ 7
Loss before income taxes	**(7)**	(6)
Income tax benefit	**1**	2
Net loss from discontinued operations	**(6)**	(4)
Gain on disposal of discontinued operations, including income tax expense of $2	**7**	–
Earnings (loss) from discontinued operations	**$ 1**	$ (4)

D. OTHER DIVERSIFIED BUSINESSES

On October 2, 2006, we sold our natural gas drilling and production business (Gas) to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $1 million (net of $1 million tax benefit) during the three months ended March 31, 2007, primarily related to working capital adjustments. The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations.

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. During the three months ended March 31, 2008, we recorded an after-tax gain on disposal of $1 million in connection with a reduction of guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners, LLC (See Note 13B). The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. The accompanying consolidated financial statements reflect the operations of Progress Rail as discontinued operations.

Also included in discontinued operations are earnings from other fuels businesses of $1 million, net of tax, for the three months ended March 31, 2007.

E. NET ASSETS OF DISCONTINUED OPERATIONS

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of Coal Mining operations were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)		December 31, 2007
Inventory	$	6
Other current assets		2
Total property, plant and equipment, net		38
Total other assets		6
Assets to be divested	$	52
Accrued expenses	$	3
Long-term liabilities		5
Liabilities to be divested	$	8

F. CEREDO SYNTHETIC FUELS INTERESTS

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo, a subsidiary that produced and sold qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a non-recourse note receivable of $54 million. Payments on the note were due as we produced and sold qualifying synthetic fuels on behalf of the buyer. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million during the year ended December 31, 2007, and a final payment of $5 million during the three months ended March 31, 2008. The note had an interest rate equal to the three-month London Inter Bank Offering Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million. Under the terms of the agreement, the purchase price was reduced by $7 million during the three months ended March 31, 2008, based on the final value of the 2007 Section 29/45 tax credits.

Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. During the three months ended March 31, 2008, we recorded gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of

December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FIN 46R, but recorded a 100 percent minority interest. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the gain on disposal in future periods. See general discussion of guarantees at Note 13B.

4. REGULATORY MATTERS

A. PEC RETAIL RATE MATTERS

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In June 2002, the North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation.

During the rate freeze period, the legislation provided for a minimum amortization and recovery of 70 percent of the original estimated compliance costs of $813 million (or $569 million) while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. For the three months ended March 31, 2008 and 2007, PEC recognized amortization of $15 million and $8 million, respectively. PEC has recognized $584 million in cumulative amortization through March 31, 2008.

Additionally, among other things, PEC requested in its March 23, 2007 petition that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue allowance for funds used during construction (AFUDC) on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

See Note 12B for additional information about the Clean Smokestacks Act.

FUEL COST RECOVERY

On April 30, 2008, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC is asking the SCPSC to approve a $39 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. If approved, the increase would take effect July 1, 2008 and would increase residential electric bills by $5.86 per 1,000 kilowatt-hours (kWh), or 6.1 percent, for fuel cost recovery. A hearing on the matter has been scheduled by the SCPSC for June 12, 2008. We cannot predict the outcome of this matter.

OTHER MATTERS

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of new demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs

that are intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. Energy-efficiency programs help our customers reduce energy use and reduce the emissions that contribute to global climate change. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred an immaterial amount of implementation and program costs for future recovery. On April 29 and May 1, 2008, PEC filed for NCUC approval of a total of five DSM and energy-efficiency programs, including the EnergyWise™ and distribution system demand response programs discussed below.

On April 29, 2008, PEC filed for approval by the NCUC of its EnergyWise™ program, which is a residential program that offers customers an incentive to permit PEC to remotely adjust central air conditioning and heat pumps in PEC's eastern control area and electric resistance heating and water heaters in PEC's western control area in order to reduce peak demand. PEC's goal for EnergyWise™ is to have the capability to reduce peak electricity demand by 200 MW by 2017.

Also on April 29, 2008, PEC filed for NCUC approval of its distribution system demand response program, which will provide additional capability for reducing and shifting peak electricity demand. The program also will reduce the level of natural electricity loss experienced over long distribution feeder lines, thereby eliminating the need for additional power generation to compensate for the line losses. PEC anticipates that the program will require an investment of approximately $260 million over five years and is expected to reduce peak demand by 250 MW. This distribution system investment is part of PEC's broader "Smart Grid" strategy and is expected to provide a foundation for additional initiatives, including enhanced system reliability (through faster outage isolation and response) and new capabilities for incorporating renewable energy resources and other distributed generation into PEC's energy mix. Such costs are expected to be recovered under the provisions of the North Carolina comprehensive energy legislation.

We cannot predict the outcome of the April 29 and May 1, 2008 filings or whether the proposed programs will produce the expected operational and economic results.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred an immaterial amount of implementation and program costs for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy-efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. These rules provide filing requirements associated with the legislation. The order requires PEC to submit its first annual North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan by September 1, 2008, as part of its integrated resource plan. Under the new rules, beginning in 2009, PEC will also be required to file an annual REPS compliance report demonstrating the actions it has taken to comply with the REPS requirement. The rules measure compliance with the REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC will pursue a third-party REC tracking system, but will not develop or require participation in a REC trading platform at this time. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the REPS clause will be set based on projected costs with true-up provisions.

On April 30, 2008, PEC filed an Application for Certificate of Public Convenience and Necessity with the NCUC to construct a 600 MW combined cycle duel fuel capable generating facility at its Richmond County generation site. We cannot predict the outcome of this matter.

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent as well as recovery of the wholesale portion of the terminated GridSouth Transco, LLC (GridSouth) project startup costs over five years. If approved by FERC, the new rates would be effective July 1, 2008, and PEC estimates the impact of the new rates will increase 2008 revenues by $6 million to $8 million. We cannot predict the outcome of this matter.

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (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; no consensus was reached on creating a southeast RTO. 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.

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. PEC's recorded investment in GridSouth totaled $22 million at March 31, 2008 and December 31, 2007. PEC expects to recover its GridSouth development costs based on precedent regulatory proceedings. We cannot predict the outcome of this matter.

B. PEF RETAIL RATE MATTERS

PASS-THROUGH CLAUSE COST RECOVERY

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. Neither PEF nor OPC filed an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices have been prudent. We anticipate that a hearing will be held on the 2006 and 2007 coal purchases in January 2009. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate Crystal River Unit No. 3 Nuclear Plant (CR3), bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification. The petition filed with the FPSC included estimated project costs of approximately $382 million. These cost estimates may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, estimated at $6 million of direct costs, through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy legislation enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On February 29, 2008, PEF filed a petition for recovery of costs incurred in 2007 and 2006 under Florida's comprehensive energy legislation and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. The FPSC is scheduled to vote on this matter by October 2008. We cannot predict the outcome of this matter.

On May 1, 2008, PEF filed with the FPSC for an increase in the capacity cost-recovery charge under the FPSC nuclear cost-recovery rule. PEF is asking the FPSC to approve a $25 million increase in the capacity cost recovery revenue requirement for costs associated with the CR3 uprate. If approved, the increase would take effect with the first billing cycle for 2009 and would increase residential electric bills by $0.70 per 1,000 kWh. Also included in this filing was a revision to the estimate provided in the need determination proceeding to include indirect costs, for a total original estimate of $439 million. After PEF's completion of a transmission study and additional engineering studies, the current project estimate is $364 million. A hearing on the matter has been scheduled by the FPSC for September 2008, and the FPSC is scheduled to vote on this matter by October 2008. We cannot predict the outcome of this matter.

OTHER MATTERS

On March 11, 2008, PEF filed a petition for an affirmative Determination of Need for its proposed Levy Units 1 and 2 nuclear power plants, together with the associated facilities, including transmission lines and substation facilities. Levy Units 1 and 2 are needed to maintain electric system reliability and integrity, fuel and generating diversity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,092 MW (summer rating). PEF proposes to place Levy Unit 1 in service by June 2016 and Levy Unit 2 in service by June 2017. The filed, non-binding project cost estimate for Levy Units 1 and 2 is approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. A hearing is scheduled for May 21-23, 2008, and a vote by the FPSC is scheduled for July 15, 2008. We cannot predict the outcome of this matter.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of the proposed Levy nuclear project. PEF filed the petition to assist the FPSC in the timely and adequate review of the projects costs recoverable under the FPSC nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009. Additionally, the filing included site selection costs of $38 million. Subsequent to an affirmative determination of need from the FPSC on the Levy nuclear project, PEF intends to file a formal petition to recover all prudently incurred costs under the FPSC nuclear cost-recovery rule. A decision by the FPSC on PEF's 2008 cost-recovery filing is expected by October 2008. We cannot predict the outcome of this matter.

5. EQUITY AND COMPREHENSIVE INCOME

A. EARNINGS PER COMMON SHARE

A reconciliation of our weighted-average number of common shares outstanding for basic and dilutive earnings per share purposes follows:

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Weighted-average common shares – basic	**259**	254
Net effect of dilutive stock-based compensation plans	**–**	1
Weighted-average shares – fully dilutive	**259**	255

B. COMPREHENSIVE INCOME

Progress Energy

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Net income	**$ 209**	$ 275
Other comprehensive income (loss)		
Reclassification adjustments included in net income		
Change in cash flow hedges (net of tax expense of $-)	**1**	–
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $ -)	**–**	1
Net unrealized losses on cash flow hedges (net of tax benefit of $6)	**(9)**	–
Other (net of tax benefit of $3)	**–**	(2)
Other comprehensive loss	**(8)**	(1)
Comprehensive income	**$ 201**	$ 274

PEC

(in millions)	Three Months Ended March 31, 2008	2007
Net income	**$ 123**	$ 124
Other comprehensive loss		
Net unrealized losses on cash flow hedges (net of tax benefit of $3 and $1, respectively)	**(5)**	(1)
Other (net of tax benefit of $1)	**–**	(4)
Other comprehensive loss	**(5)**	(5)
Comprehensive income	**$ 118**	$ 119

PEF

(in millions)	Three Months Ended March 31, 2008	2007
Net income	**$ 67**	$ 61
Other comprehensive loss		
Net unrealized losses on cash flow hedges (net of tax benefit of $3)	**(4)**	–
Other comprehensive loss	**(4)**	–
Comprehensive income	**$ 63**	$ 61

C. COMMON STOCK

At December 31, 2007, we had 500 million shares of common stock authorized under our charter, of which approximately 260 million were outstanding. At December 31, 2007, we had approximately 50 million unissued shares of common stock 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. For the three months ended March 31, 2008 and 2007, respectively, we issued approximately 0.5 million shares and 1.5 million shares of common stock resulting in approximately $20 million and $65 million in proceeds. Included in these amounts were approximately 0.4 million shares and 0.2 millions shares, respectively, for proceeds of approximately $19 million and $11 million, respectively, to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan.

6. DEBT AND CREDIT FACILITIES AND FINANCING ACTIVITIES

Material changes, if any, to Progress Energy's, PEC's and PEF's debt and credit facilities and financing activities since December 31, 2007, are described below.

On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.

On March 12, 2008, PEC and PEF amended their revolving credit agreements (RCA) with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA is now scheduled to expire on June 28, 2011, and PEF's RCA is now scheduled to expire on March 28, 2011.

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.650% Medium-Term Notes, Series D, due April 1, 2008 and the remainder was placed in temporary investments for general corporate use as needed.

On April 14, 2008, we amended our RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 3, 2008. Our RCA is now scheduled to expire on May 3, 2012.

7. FAIR VALUE MEASUREMENTS

In September 2006, the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value under GAAP, and requires enhanced disclosures about assets and liabilities carried at fair value. SFAS No. 157 also establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. In February 2008, the FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which delays for us the effective date of SFAS No. 157 until January 1, 2009, for all nonfinancial assets and nonfinancial liabilities, except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

We implemented SFAS No. 157 as of January 1, 2008, for all recurring financial assets and liabilities. The adoption of SFAS No. 157 for recurring financial assets and liabilities did not have a material impact on our or the Utilities' financial position or results of operations. We utilized the deferral provision of FSP No. FAS 157-2 for all nonrecurring nonfinancial assets and liabilities within its scope. Major categories of our assets and liabilities to which the deferral applies include reporting units and long-lived asset groups measured at fair value for impairment purposes, asset retirement obligations initially recognized at fair value, and nonfinancial liabilities for exit and disposal costs and indemnifications initially measured at fair value. We do not expect the January 1, 2009 adoption of SFAS No. 157 for nonrecurring nonfinancial assets and liabilities to have a material impact on our or the Utilities' financial position or results of operations.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient and requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. SFAS No. 157 requires that valuation techniques maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

> Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.
>
> Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards, swaps and options, certain marketable debt securities, and financial instruments traded in less than active markets.
>
> Level 3 – The pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods where quoted prices or other observable inputs are not available. At each balance sheet date, we perform an analysis of all instruments subject to SFAS No. 157 and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The following tables set forth by level within the fair value hierarchy our and the Utilities' financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2008. As required by SFAS No. 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Progress Energy

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:				
Commodity derivatives	$ –	$ 372	$ 55	$ 427
Nuclear decommissioning trust funds	785	528	–	1,313
Other marketable securities	9	40	–	49
Total assets	$ 794	$ 940	$ 55	$ 1,789
Liabilities:				
Commodity derivatives	$ –	$ (10)	$ –	$ (10)
Interest rate derivatives	–	(7)	–	(7)
CVO derivatives	–	(34)	–	(34)
Total liabilities	$ –	$ (51)	$ –	$ (51)

PEC

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:				
Commodity derivatives	$ –	$ 37	$ 12	$ 49
Nuclear decommissioning trust funds	444	327	–	771
Total assets	$ 444	$ 364	$ 12	$ 820
Liabilities:				
Commodity derivatives	$ –	$ (1)	$ –	$ (1)
Total liabilities	$ –	$ (1)	$ –	$ (1)

PEF

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:				
Commodity derivatives	$ –	$ 335	$ 43	$ 378
Nuclear decommissioning trust funds	341	201	–	542
Total assets	$ 341	$ 536	$ 43	$ 920
Liabilities:				
Commodity derivatives	$ –	$ (9)	$ –	$ (9)
Interest rate derivatives	–	(7)	–	(7)
Total liabilities	$ –	$ (16)	$ –	$ (16)

The determination of the fair values above incorporates various factors required under SFAS No. 157, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

Commodity and interest rate derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity and interest rate derivatives are valued using financial models which utilize observable inputs for similar instruments, and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 9 for discussion of risk management activities and derivative transactions.

Nuclear decommissioning trust funds reflect the assets of the Utilities' nuclear decommissioning trusts, as discussed in Note 13 of the 2007 Form 10-K. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2.

Other marketable securities represent available-for-sale debt and equity securities used to fund certain employee benefit costs.

We issued Contingent Value Obligations (CVOs) in connection with the acquisition of Florida Progress Corporation (Florida Progress), as discussed in Note 15 in the 2007 Form 10-K. The CVOs are derivatives recorded at fair value based on quoted prices from a less than active market, and are classified as Level 2.

The following tables set forth a reconciliation of changes in the fair value of our and the Utilities' commodity derivatives classified as Level 3 in the fair value hierarchy.

Progress Energy

(in millions)	
Derivatives, net at January 1, 2008	$ 26
Total gains (losses), realized and unrealized:	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	29
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	–
Derivatives, net at March 31, 2008	$ 55

PEC

(in millions)	
Derivatives, net at January 1, 2008	$ 6
Total gains (losses), realized and unrealized:	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	6
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	–
Derivatives, net at March 31, 2008	$ 12

PEF

(in millions)	
Derivatives, net at January 1, 2008	$ 20
Total gains (losses), realized and unrealized:	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	23
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	–
Derivatives, net at March 31, 2008	$ 43

Unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment.

Transfers in (out) of Level 3 represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. There were no transfers into or out of Level 3 during the period.

8. BENEFIT PLANS

We have noncontributory defined benefit retirement plans that provide pension benefits for substantially all full-time employees. 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. The components of the net periodic benefit cost for the respective Progress Registrants for the three months ended March 31 were:

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Service cost	**$ 12**	$ 11	**$ 2**	$ 2
Interest cost	**31**	30	**8**	9
Expected return on plan assets	**(41)**	(39)	**(2)**	(1)
Amortization of actuarial loss (a)	**3**	4	**1**	1
Other amortization, net (a)	**–**	–	**1**	1
Net periodic cost	**$ 5**	$ 6	**$ 10**	$ 12

(a) Adjusted to reflect PEF's rate treatment. See Note 16B in the 2007 Form 10-K.

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Service cost	**$ 6**	$ 5	**$ 1**	$ 1
Interest cost	**14**	14	**4**	5
Expected return on plan assets	**(16)**	(15)	**(1)**	(1)
Amortization of actuarial loss	**2**	3	**–**	1
Net periodic cost	**$ 6**	$ 7	**$ 4**	$ 6

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Service cost	**$ 4**	$ 4	**$ 1**	$ 1
Interest cost	**13**	13	**3**	3
Expected return on plan assets	**(21)**	(21)	**–**	–
Other amortization, net	**–**	–	**1**	1
Net periodic (benefit) cost	**$ (4)**	$ (4)	**$ 5**	$ 5

9. RISK MANAGEMENT ACTIVITIES AND DERIVATIVE 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.

As discussed in Note 7, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income. At March 31, 2008, and December, 31, 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million.

A. COMMODITY DERIVATIVES

GENERAL

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify and are elected 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 11). At March 31, 2008, and December 31, 2007, the remaining liability was $9 million and $10 million, respectively.

DISCONTINUED OPERATIONS

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Notes 1C and 3F, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, with a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact from Ceredo's operations, which ceased as of December 31, 2007. At December 31, 2007, the $234 million fair value of these contracts, including $79 million at Ceredo, was included in receivables, net on the Consolidated Balance Sheet. The contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. For the three months ended March 31, 2007, we recorded net pre-tax gains of $45 million related to these contracts, including $15 million attributable to Ceredo, of which less than $1 million was attributed to minority interest for the portion of the gain subsequent to disposal.

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.

The Utilities have derivative instruments related to their 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 on the Balance Sheets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. During the quarters ended March 31, 2008 and 2007, PEC recorded a net realized gain of less than $1 million. During the quarters ended March 31, 2008 and 2007, PEF recorded a net realized gain of $16 million and a net realized loss of $17 million, respectively.

The December 31, 2007 balances presented below reflect the retrospective adoption of FSP FIN 39-1 (See Note 2).

At March 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $13 million short-term derivative asset position included in prepayments and other current assets and $36 million long-term derivative asset position included in other assets and deferred debits on the PEC Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments were recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $4 million short-term derivative liability included in other current liabilities on the PEC Consolidated Balance Sheet. PEC had no cash collateral position at March 31, 2008 or December 31, 2007.

At March 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $204 million short-term derivative asset position included in current derivative assets, a $174 million long-term derivative asset position included in derivative assets, a $4 million short-term liability position included in derivative liabilities, and a $5 million long-term derivative liability position included in other liabilities and deferred credits on the PEF Balance Sheet. At December 31, 2007, the fair value of such instruments were recorded as a $83 million short-term derivative asset position included in current derivative assets, a $100 million long-term derivative asset position included in derivative assets, a $38 million short-term liability position included in derivative liabilities, and a $9 million long-term derivative liability position included in other liabilities and deferred credits on the PEF Balance Sheet. PEF had a $51 million cash collateral liability at March 31, 2008, included in other current liabilities on the PEF Balance Sheet, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

PEC designates 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 power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At March 31, 2008, and December 31, 2007, neither we nor the Utilities had material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for the three months ended March 31, 2008 and 2007.

At March 31, 2008, and December 31, 2007, the amount recorded in our or PEC's accumulated other comprehensive income related to commodity cash flow hedges was not material and PEF had no amount recorded in accumulated other comprehensive income 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 exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

The fair values of open interest rate hedges at March 31, 2008, and December 31, 2007, were as follows:

	March 31, 2008			December 31, 2007		
(in millions)	**Progress Energy**	**PEC**	**PEF**	Progress Energy	PEC	PEF
Fair value of liabilities	**$ (7)**	**$ –**	**$ (7)**	$ (12)	$ (12)	$ –

Gains and losses from cash flow hedges are recorded in accumulated other comprehensive income and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges for the three months ended March 31, 2008 and 2007, was not material to our or the Utilities' results of operations.

The following table presents selected information related to our interest rate cash flow hedges included in accumulated other comprehensive income at March 31, 2008:

(term in years/millions of dollars)	Progress Energy	PEC	PEF
Maximum term	Less than 1	–	Less than 1
Accumulated other comprehensive loss, net of tax[(a)]	$ (31)	$ (15)	$ (12)
Portion expected to be reclassified to earnings during the next 12 months[(b)]	$ (3)	$ (1)	$ (1)

(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, 2007, including amounts related to terminated hedges, we had $24 million of after-tax deferred losses, including $12 million of after-tax deferred losses at PEC and $8 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

At December 31, 2007, PEC had $200 million notional of interest rate cash flow hedges. All of PEC's forward starting swaps were terminated on March 13, 2008, in conjunction with PEC's issuance of $325 million of First Mortgage Bonds, 6.30% Series due 2038. The effective portion of the hedges is included in accumulated other comprehensive income and will be amortized to interest expense over the life of the related debt.

In January 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuance. On May 1, 2008, PEF entered into a $50 million notional 10-year forward starting swap and a $100 million notional 30-year forward starting swap to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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 March 31, 2008, and December 31, 2007, we and the Utilities had no open interest rate fair value hedges.

10. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable 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. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Income of discontinued operations is not included in the table presented below. For comparative purposes, the prior year results have been restated to conform to the current segment presentation. The following information is for the three months ended March 31:

(in millions)	Revenues Unaffiliated	Revenues Intersegment	Revenues Total	Income (Loss) From Continuing Operations	Assets
2008					
PEC	**$ 1,068**	**$ –**	**$ 1,068**	**$ 122**	**$ 12,287**
PEF	**996**	**–**	**996**	**66**	**10,307**
Corporate and Other	**2**	**82**	**84**	**(39)**	**16,489**
Eliminations	–	**(82)**	**(82)**	**–**	**(12,539)**
Totals	**$ 2,066**	**$ –**	**$ 2,066**	**$ 149**	**$ 26,544**

2007				
PEC	$ 1,058	$ –	$ 1,058	$ 123
PEF	1,011	–	1,011	60
Corporate and Other	3	86	89	(34)
Eliminations	–	(86)	(86)	–
Totals	$ 2,072	$ –	$ 2,072	$ 149

11. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income 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. CVOs unrealized gain or loss is due to changes in fair value. See Note 15 in the 2007 Form 10-K for more information on CVOs. The components of other, net as shown on the accompanying Statements of Income were as follows:

Progress Energy

(in millions)	Three Months Ended March 31, 2008	2007
Other income		
Nonregulated energy and delivery services income	**$ 7**	$ 9
DIG Issue C20 amortization (see Note 9A)	**1**	–
CVOs unrealized gain	**–**	1
Investment gains	**1**	1
Income from equity investments	**–**	1
AFUDC equity	**23**	9
Other	**3**	5
Total other income	**35**	26
Other expense		
Nonregulated energy and delivery services expenses	**4**	6
Donations	**4**	4
Investment losses	**3**	–
Loss from equity investments	**1**	2
Other	**5**	3
Total other expense	**17**	15
Other, net	**$ 18**	$ 11

PEC

(in millions)	Three Months Ended March 31, 2008	2007
Other income		
Nonregulated energy and delivery services income	**$ 3**	$ 2
DIG Issue C20 amortization (see Note 9A)	**1**	–
Income from equity investments	**–**	2
Investment gains	**1**	–
AFUDC equity	**4**	2
Other	**3**	4
Total other income	**12**	10
Other expense		
Nonregulated energy and delivery services expenses	**1**	2
Donations	**2**	2
Loss from equity investments	**1**	1
Other	**4**	2
Total other expense	**8**	7
Other, net	**$ 4**	$ 3

PEF

(in millions)	Three Months Ended March 31, 2008	2007
Other income		
Nonregulated energy and delivery services income	**$ 4**	$ 7
AFUDC equity	**19**	7
Other	**1**	–
Total other income	**24**	14
Other expense		
Nonregulated energy and delivery services expenses	**3**	5
Donations	**2**	2
Investment losses	**2**	–
Total other expense	**7**	7
Other, net	**$ 17**	$ 7

12. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. 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 frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. HAZARDOUS AND SOLID WASTE

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States 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, the state of Florida, or potentially responsible party (PRP) groups 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 PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

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.

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, were:

(in millions)	**March 31, 2008**	December 31, 2007
PEC		
MGP and other sites[a]	**$ 15**	$ 16
PEF		
Remediation of distribution and substation transformers	**27**	31
MGP and other sites	**17**	17
Total PEF environmental remediation accruals[b]	**44**	48
Total Progress Energy environmental remediation accruals	**$ 59**	$ 64

[a] Expected to be paid out over one to five years.

[b] Expected to be paid out over one to fifteen years.

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.

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 Note 13B).

PEC

For the three months ended March 31, 2008, including the Ward Transformer site and MGP sites discussed below, PEC accrued approximately $1 million and spent approximately $2 million, primarily related to the Ward Transformer site. For the three months ended March 31, 2007, PEC reduced its accrual by approximately $5 million, primarily related to the Ward Transformer site, and spent approximately $1 million. PEC defers and amortizes certain environmental remediation expenses in accordance with orders received from the NCUC and SCPSC.

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

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 the EPA's past expenditures in addressing conditions at the site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced PEC's allocable share, and the estimated scope of work increased. These factors resulted in a net reduction to PEC's accrual for this site. At December 31, 2007, PEC's recorded liability for the site was approximately $6 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

The EPA has also proposed, but not yet selected, a final remedial action plan to address stream segments downstream from the Ward Transformer site. The outcome of this matter cannot be predicted.

PEF

PEF has received approval from the FPSC for recovery through the Environmental Cost Recovery Clause (ECRC) of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the three months ended March 31, 2008 and 2007, PEF accrued approximately $2 million due to increases in estimated remediation costs and spent approximately $6 million and $5 million, respectively, related to the remediation of transformers. At March 31, 2008, PEF had 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. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the three months ended March 31, 2008 and 2007, PEF made no additional accruals or material expenditures.

B. AIR AND WATER QUALITY

We are subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations include the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call), the Clean Smokestacks Act and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At March 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.753 billion, including $1.274 billion at PEC and $479 million at PEF. At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.567 billion, including $1.244 billion at PEC and $323 million at PEF.

As discussed in Note 4A, 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. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At March 31, 2008 and December 31, 2007, the amount of the liability was $25 million and $30 million, respectively, based upon the respective estimates for the remaining Clean Smokestacks Act compliance costs. During the three months ended March 31, 2008, PEC made no additional accruals and spent approximately $5 million that exceeded the joint owner limit. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. In a settlement agreement provisionally approved by the NCUC on December 20, 2007, eligible compliance costs in excess of the joint owner's share will be treated in the same manner as PEC's Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs, as ultimately approved by the NCUC (See Note 4A).

13. COMMITMENTS AND CONTINGENCIES

Contingencies and significant changes to the commitments discussed in Note 22 in the 2007 Form 10-K are described below.

A. PURCHASE OBLIGATION

PROGRESS ENERGY

As part of our ordinary course of business, we enter into various long- and short-term contracts for fuel requirements at our generating plants. Through March 31, 2008, contracts procured through our subsidiaries have increased our aggregate purchase obligations for fuel and purchased power by $4.287 billion from $17.644 billion, as stated in Note 22A in the 2007 Form 10-K. This increase is discussed under "PEC" and "PEF" below.

PEC

Through March 31, 2008, PEC's fuel and purchase power commitments increased by $3.248 billion from $5.078 billion, as stated in Note 22A in the 2007 Form 10-K. This increase is primarily related to coal purchase commitments, of which approximately $2 billion will be incurred through 2012, with the remainder incurred through 2018.

PEF

Through March 31, 2008, PEF's fuel and purchase power commitments increased by $1.039 billion from $12.566 billion as stated in Note 22A in the 2007 Form 10-K. Approximately $640 million of this increase is due to coal purchase commitments, of which approximately $191 million will be incurred through 2012, with the remainder incurred through 2018. Additionally, approximately $470 million of the increase will be incurred in the period 2014 through 2027 and is due to the impact of rising natural gas prices under a long-term gas supply agreement that was entered into in December 2004. Payments under this agreement are based on a published market price index. Contractual obligations under this contract are based on estimated future market prices.

B. 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 45). Such agreements include guarantees, standby letters of credit and surety bonds. At March 31, 2008, 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 March 31, 2008, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, which are within the scope of FIN 45. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement 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 liability related to this indemnification (See Note 12B). PEC's maximum exposure cannot be determined. At March 31, 2008, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. At March 31, 2008 and December 31, 2007, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $78 million and $80 million, respectively. These amounts include $25 million and $30 million, respectively, for PEC and $8 million for PEF at March 31, 2008, and December 31, 2007. During the three months ended March 31, 2008, PEC made no additional accruals and spent approximately $5 million that exceeded the joint owner limit. 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 and a subsidiary have has issued $300 million of guarantees for certain payments of two wholly owned indirect subsidiaries. See Note 14 for additional information.

C. OTHER COMMITMENTS AND CONTINGENCIES

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the United States Department of Energy (DOE) under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

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. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims. The Utilities have asserted nearly $91 million in damages incurred between January 31, 1998 and December 31, 2005; the time period set by the court for damages in this case. The Utilities will be free to file subsequent damages claims as they incur additional costs.

A trial was held in November 2007, and closing arguments presented on April 4, 2008. We expect a ruling later in 2008. The Utilities cannot predict the outcome of this matter. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment.

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 the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged 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 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 subsequently reported that the license application would be submitted by June 2008 if full funding was obtained for the project. The DOE requested $545 million for fiscal year 2007 and received $445 million. The DOE requested $495 million for fiscal year 2008. However, Congress passed an appropriations bill which allocates $390 million in fiscal year 2008 for DOE's Yucca Mountain repository program. Despite the cuts in requested funding, the DOE is expected to submit the license application by the end of June 2008.

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more likely due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation of on-site dry cask storage facilities at PEC's Robinson Nuclear Plant, PEC's Brunswick Nuclear Plant 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 their nuclear generating units. PEC's Shearon Harris Nuclear Plant (Harris) has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

SYNTHETIC FUELS MATTERS

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); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; 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 (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims related to the contracts.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.* (the Florida Global Case), asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003, and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. 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* (the North Carolina Global Case), 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. 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, but stayed 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. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The Florida Global Case continues now under contract theories alone. The case is scheduled to go to trial in April 2009. We cannot predict the outcome of this matter.

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 "Accounting for Contingencies" to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

14. CONDENSED CONSOLIDATING STATEMENTS

As discussed in Note 23 in the 2007 Form 10-K, we have guaranteed certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.) since September 2005. 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 in the 2007 Form 10-K, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and was deconsolidated in 2003 in accordance with the provisions of FIN 46R. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

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 these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only, which is primarily comprised of its wholly owned subsidiary PEF. The Other column includes the consolidated financial results of all other non-guarantor subsidiaries, primarily our wholly owned subsidiary PEC, and elimination entries for all intercompany transactions. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-Q. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of Terminals and the synthetic fuels businesses as discontinued operations as described in Note 3A.

Condensed Consolidating Statement of Income
Three months ended March 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues	$ –	$ 998	$ 1,068	$ 2,066
Operating expenses				
Fuel used in electric generation	–	341	356	697
Purchased power	–	183	49	232
Operation and maintenance	–	203	240	443
Depreciation and amortization	–	76	130	206
Taxes other than on income	–	71	50	121
Other	–	2	–	2
Total operating expenses	–	876	825	1,701
Operating income	–	122	243	365
Other income, net	4	15	6	25
Interest charges, net	48	51	54	153
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(44)	86	195	237
Income tax (benefit) expense	(18)	27	75	84
Equity in earnings of consolidated subsidiaries	235	–	(235)	–
Minority interest in subsidiaries' income, net of tax	–	(4)	–	(4)
Income (loss) from continuing operations	209	55	(115)	149
Discontinued operations, net of tax	–	56	4	60
Net income (loss)	$ 209	$ 111	$ (111)	$ 209

Condensed Consolidating Statement of Income
Three months ended March 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues	$ –	$ 1,014	$ 1,058	$ 2,072
Operating expenses				
Fuel used in electric generation	–	385	351	736
Purchased power	–	163	58	221
Operation and maintenance	5	175	240	420
Depreciation and amortization	–	97	122	219
Taxes other than on income	–	74	50	124
Other	–	(1)	2	1
Total operating expenses	5	893	823	1,721
Operating (loss) income	(5)	121	235	351
Other income, net	6	8	5	19
Interest charges, net	49	44	49	142
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(48)	85	191	228
Income tax (benefit) expense	(20)	25	67	72
Equity in earnings of consolidated subsidiaries	302	–	(302)	–
Minority interest in subsidiaries' income, net of tax	–	(7)	–	(7)
Income (loss) from continuing operations	274	53	(178)	149
Discontinued operations, net of tax	1	29	96	126
Net income (loss)	$ 275	$ 82	$ (82)	$ 275

Condensed Consolidating Balance Sheet
March 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 7,921	$ 9,065	$ 16,986
Current assets				
Cash and cash equivalents	19	83	298	400
Receivables, net	–	313	454	767
Notes receivable from affiliated companies	35	38	(73)	–
Derivative assets	–	204	13	217
Prepayments and other current assets	37	525	652	1,214
Total current assets	91	1,163	1,344	2,598
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,325	–	(11,325)	–
Goodwill	–	–	3,655	3,655
Derivative assets	–	174	36	210
Other assets and deferred debits	147	1,507	1,441	3,095
Total deferred debits and other assets	11,472	1,681	(6,193)	6,960
Total assets	$ 11,563	$ 10,765	$ 4,216	$ 26,544
Capitalization				
Common stock equity	$ 8,518	$ 3,243	$ (3,243)	$ 8,518
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	2	4	6
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,687	3,107	8,391
Total capitalization	11,115	6,275	(111)	17,279
Current liabilities				
Current portion of long-term debt	–	497	700	1,197
Notes payable to affiliated companies	–	175	(175)	–
Other current liabilities	404	1,156	629	2,189
Total current liabilities	404	1,828	1,154	3,386
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	51	237	288
Regulatory liabilities	–	1,544	1,231	2,775
Other liabilities and deferred credits	44	1,067	1,705	2,816
Total deferred credits and other liabilities	44	2,662	3,173	5,879
Total capitalization and liabilities	$ 11,563	$ 10,765	$ 4,216	$ 26,544

Condensed Consolidating Balance Sheet
December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 7,600	$ 9,005	$ 16,605
Current assets				
Cash and cash equivalents	185	43	27	255
Receivables, net	–	574	593	1,167
Notes receivable from affiliated companies	157	149	(306)	–
Derivative assets	–	83	2	85
Assets to be divested	–	48	4	52
Prepayments and other current assets	21	595	654	1,270
Total current assets	363	1,492	974	2,829
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,969	–	(10,969)	–
Goodwill	–	1	3,654	3,655
Derivative assets	–	100	19	119
Other assets and deferred debits	149	1,475	1,533	3,157
Total deferred debits and other assets	11,118	1,576	(5,763)	6,931
Total assets	$ 11,481	$ 10,668	$ 4,216	$ 26,365
Capitalization				
Common stock equity	$ 8,422	$ 3,052	$ (3,052)	$ 8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	81	3	84
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,686	3,183	8,466
Total capitalization	11,019	6,162	155	17,336
Current liabilities				
Current portion of long-term debt	–	577	300	877
Notes payable to affiliated companies	–	227	(227)	–
Liabilities to be divested	–	8	–	8
Other current liabilities	416	1,237	764	2,417
Total current liabilities	416	2,049	837	3,302
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	59	302	361
Regulatory liabilities	–	1,330	1,224	2,554
Other liabilities and deferred credits	46	1,068	1,698	2,812
Total deferred credits and other liabilities	46	2,457	3,224	5,727
Total capitalization and liabilities	$ 11,481	$ 10,668	$ 4,216	$ 26,365

Condensed Consolidating Statement of Cash Flows
Three months ended March 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$ (55)	$ 393	$ 439	$ 777
Investing activities				
Gross property additions	–	(446)	(172)	(618)
Nuclear fuel additions	–	–	(41)	(41)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	94	1	95
Proceeds from sales of assets to affiliated companies	–	8	(8)	–
Purchases of available-for-sale securities and other investments	–	(247)	(241)	(488)
Proceeds from sales of available-for-sale securities and other investments	–	247	226	473
Changes in advances to affiliates	122	111	(233)	–
Other investing activities	(97)	14	77	(6)
Net cash provided (used) by investing activities	25	(219)	(391)	(585)
Financing activities				
Issuance of common stock	20	–	–	20
Dividends paid on common stock	(159)	–	–	(159)
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	(176)
Net increase in short-term debt	180	–	–	180
Proceeds from issuance of long-term debt, net	–	–	322	322
Retirement of long-term debt	–	(80)	–	(80)
Cash distributions to minority interests of consolidated subsidiaries	–	(85)	–	(85)
Dividends paid to parent	–	(3)	3	–
Changes in advances from affiliates	–	(53)	53	–
Other financing activities	(1)	87	(155)	(69)
Net cash (used) provided by financing activities	(136)	(134)	223	(47)
Net (decrease) increase in cash and cash equivalents	(166)	40	271	145
Cash and cash equivalents at beginning of period	185	43	27	255
Cash and cash equivalents at end of period	$ 19	$ 83	$ 298	$ 400

Condensed Consolidating Statement of Cash Flows
Three months ended March 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$ (8)	$ 31	$ 293	$ 316
Investing activities				
Gross property additions	–	(262)	(209)	(471)
Nuclear fuel additions	–	(23)	(38)	(61)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	25	5	30
Purchases of available-for-sale securities and other investments	–	(44)	(148)	(192)
Proceeds from sales of available-for-sale securities and other investments	21	44	187	252
Changes in advances to affiliates	(180)	37	143	–
Other investing activities	(2)	(5)	7	–
Net cash used by investing activities	(161)	(228)	(53)	(442)
Financing activities				
Issuance of common stock	65	–	–	65
Dividends paid on common stock	(155)	–	–	(155)
Net increase in short-term debt	117	–	–	117
Changes in advances from affiliates	–	187	(187)	–
Other financing activities	(1)	11	(43)	(33)
Net cash provided (used) by financing activities	26	198	(230)	(6)
Net (decrease) increase in cash and cash equivalents	(143)	1	10	(132)
Cash and cash equivalents at beginning of period	153	40	72	265
Cash and cash equivalents at end of period	$ 10	$ 41	$ 82	$ 133

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following combined Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) 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). 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,” “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. Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. 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 following MD&A 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 “Safe Harbor for Forward-Looking Statements” and Item 1A, “Risk Factors” found within Part II of this Form 10-Q and Item 1A, “Risk Factors” to the Progress Registrant’s annual report on Form 10-K for the fiscal year ended December 31, 2007 (2007 Form 10-K) for a discussion of the factors that may impact any such forward-looking statements made herein.

Amounts reported in the interim statements of income are not necessarily indicative of amounts expected for the respective annual or future periods due to the effects of weather variations and the timing of outages of electric generating units, especially nuclear-fueled units, among other factors.

This discussion should be read in conjunction with the accompanying financial statements found elsewhere in this report and in conjunction with the 2007 Form 10-K.

PROGRESS ENERGY

RESULTS OF OPERATIONS

Our reportable operating business segments are PEC and PEF, which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina, and Florida, respectively.

Our “Corporate and Other” segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment.

As discussed more fully in Note 3 and “Results of Operations – Discontinued Operations,” in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, the majority of our nonregulated business operations have been divested. These operations have been classified as discontinued operations in the accompanying financial statements. Consequently, the composition of other continuing segments has been impacted by these divestitures. For comparative purposes, prior year results have been restated to conform to the current presentation. In this section, earnings and the factors affecting earnings for the three months ended March 31, 2008, are compared to the same period in 2007. 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 the quarter ended March 31, 2008, our net income was $209 million, or $0.81 per share, compared to net income of $275 million, or $1.08 per share, for the same period in 2007. For each of the quarters ended March 31, 2008 and 2007, our income from continuing operations was $149 million. Our income from continuing operations as compared to prior year was positively impacted by:

- favorable allowance for funds used during construction (AFUDC) equity at PEF;
- favorable retail customer growth and usage at PEC;
- increased retail rates at PEF;
- lower purchased power expense at PEC due to the expiration of a power buyback agreement; and
- higher wholesale revenues at PEF.

Offsetting these items were:

- lower wholesale revenues at PEC;
- higher depreciation and amortization expense excluding prior year recoverable storm amortization at the Utilities;
- higher interest expense at PEF due to higher average debt outstanding;
- unfavorable retail customer growth and usage at PEF; and
- unfavorable weather at PEC.

Our segments contributed the following profits or losses for the three months ended March 31, 2008 and 2007:

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Business Segment		
PEC	**$ 122**	$ 123
PEF	**66**	60
Total segment profit	**188**	183
Corporate and Other	**(39)**	(34)
Income from continuing operations	**149**	149
Discontinued operations, net of tax	**60**	126
Net income	**$ 209**	$ 275

PROGRESS ENERGY CAROLINAS

PEC contributed segment profits of $122 million and $123 million for the three months ended March 31, 2008 and 2007, respectively. The decrease in profits for the three months ended March 31, 2008, compared to the same period in 2007, was primarily due to lower wholesale revenues, higher North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization and the unfavorable impact of weather, partially offset by the favorable impact of retail customer growth and usage and lower purchased power expense due to the expiration of a power buyback agreement.

The revenue table below presents the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel is defined as total electric revenues less fuel revenues. We and PEC consider revenues excluding fuel a useful measure to evaluate PEC's electric operations because fuel revenues primarily represent the recovery of fuel and a portion of purchased power expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We and PEC have included the analysis below as a complement to the financial information we provide in accordance with accounting principles generally accepted in the United States of America (GAAP). However, revenues excluding fuel is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

PEC’s electric revenues for the three months ended March 31, 2008 and 2007, and the amount and percentage change by customer class were as follows:

(in millions)	Three Months Ended March 31,			
Customer Class	**2008**	Change	% Change	2007
Residential	**$ 426**	$ 2	0.5	$ 424
Commercial	**262**	8	3.1	254
Industrial	**168**	3	1.8	165
Governmental	**23**	1	4.5	22
Total retail revenues	**879**	14	1.6	865
Wholesale	**181**	(13)	(6.7)	194
Unbilled	**(17)**	8	–	(25)
Miscellaneous	**24**	1	4.3	23
Total electric revenues	**1,067**	10	0.9	1,057
Less: Fuel revenues	**(390)**	(15)	–	(375)
Revenues excluding fuel	**$ 677**	$ (5)	(0.7)	$ 682

PEC’s electric energy sales for the three months ended March 31, 2008 and 2007, and the amount and percentage change by customer class were as follows:

(in millions of kWh)	Three Months Ended March 31,			
Customer Class	**2008**	Change	% Change	2007
Residential	**4,678**	(62)	(1.3)	4,740
Commercial	**3,278**	33	1.0	3,245
Industrial	**2,772**	(49)	(1.7)	2,821
Governmental	**333**	6	1.8	327
Total retail energy sales	**11,061**	(72)	(0.6)	11,133
Wholesale	**3,772**	(184)	(4.7)	3,956
Unbilled	**(241)**	102	–	(343)
Total kWh sales	**14,592**	(154)	(1.0)	14,746

PEC’s revenues, excluding fuel revenues of $390 million and $375 million for the three months ended March 31, 2008 and 2007, respectively, decreased $5 million. The decrease in revenues excluding fuel is primarily due to $15 million lower wholesale revenues and the $6 million unfavorable impact of weather, partially offset by the $14 million favorable impact of retail customer growth and usage. Lower wholesale revenues excluding fuel are primarily due to $12 million lower excess generation revenues driven by unfavorable market conditions in 2008 compared to 2007 resulting from higher fuel costs. The unfavorable impact of weather was equally driven by heating and cooling degree days lower than 2007. Both heating and cooling degree days were also lower than normal. Favorable retail customer growth and usage was driven by a 26,000 customer increase in PEC's average net number of customers for the three months ended March 31, 2008, compared to the same period in 2007, and by an increase in the average usage per retail customer.

Total retail revenues increased for the three months ended March 31, 2008, despite a decrease in total retail energy sales for the same period primarily due to the impact of increased fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

The decline in general economic conditions, including weakness in the housing markets in both Florida and the United States, has contributed to a slowdown in customer growth and usage in PEF's service territory (See "Progress Energy Florida - Revenues"). PEC has not been as significantly impacted by the decline in general economic conditions as PEF.

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 a portion of 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 from or refund to customers.

Fuel and purchased power expenses were $405 million for the three months ended March 31, 2008, which represents a $4 million decrease compared to the same period in 2007. Current year purchased power costs were $9 million lower than the three months ended March 31, 2007, primarily due to the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Additionally, deferred fuel expense decreased $11 million due to the implementation of the North Carolina comprehensive energy legislation. The decrease in deferred fuel expense was partially offset by an increase of $10 million due to the collection in the current year of prior years' under-recovery.

Depreciation and Amortization

Depreciation and amortization expense was $126 million for the three months ended March 31, 2008, which represents a $9 million increase compared to the same period in 2007. Depreciation and amortization expense increased primarily due to $7 million higher Clean Smokestacks Act amortization and the impact of depreciable asset base increases.

Income Tax Expense

Income tax expense increased $6 million for the three months ended March 31, 2008, as compared to the same period in 2007, primarily due to $4 million prior year changes in tax estimates, the $3 million unfavorable tax impact of employee benefits and the $2 million tax impact of higher pre-tax earnings, partially offset by the $2 million impact of tax levelization. GAAP requires companies to apply a levelized effective tax rate to interim periods that is consistent with the estimated annual effective tax rate. PEC's income tax expense was decreased by $3 million for the three months ended March 31, 2008 compared to a decrease of $1 million for the three months ended March 31, 2007, in order to maintain an effective tax rate consistent with the estimated annual rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Therefore, this adjustment will vary each quarter, but will have no effect on net income for the year.

PROGRESS ENERGY FLORIDA

PEF contributed segment profits of $66 million and $60 million for the three months ended March 31, 2008 and 2007, respectively. The increase in profits for the three months ended March 31, 2008, compared to the same period in 2007, was primarily due to favorable AFUDC, an increase in retail rates and higher wholesale revenues, partially offset by higher interest charges, the unfavorable impact of retail customer growth and usage and higher depreciation and amortization expense excluding prior year recoverable storm amortization.

The revenue table below presents the total amount and percentage change of revenues excluding fuel and other pass-through revenues. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We and PEF consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We and PEF have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, revenues excluding fuel and other pass-through revenues is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

PEF's electric revenues for the three months ended March 31, 2008 and 2007, and the amount and percentage change by customer class were as follows:

(in millions)	Three Months Ended March 31,			
Customer Class	**2008**	Change	% Change	2007
Residential	**$ 464**	$ (27)	(5.5)	$ 491
Commercial	**242**	(5)	(2.0)	247
Industrial	**69**	(5)	(6.8)	74
Governmental	**67**	–	–	67
Total retail revenues	**842**	(37)	(4.2)	879
Wholesale	**103**	23	28.8	80
Unbilled	**6**	(2)	–	8
Miscellaneous	**45**	1	2.3	44
Total electric revenues	**996**	(15)	(1.5)	1,011
Less: Fuel and other pass-through revenues	**(608)**	37	–	(645)
Revenues excluding fuel and other pass-through revenues	**$ 388**	$ 22	6.0	$ 366

PEF's electric energy sales for the three months ended March 31, 2008 and 2007, and the amount and percentage change by customer class are as follows:

(in millions of kWh)	Three Months Ended March 31,			
Customer Class	**2008**	Change	% Change	2007
Residential	**4,005**	(150)	(3.6)	4,155
Commercial	**2,661**	37	1.4	2,624
Industrial	**865**	(30)	(3.4)	895
Governmental	**767**	19	2.5	748
Total retail energy sales	**8,298**	(124)	(1.5)	8,422
Wholesale	**1,390**	220	18.8	1,170
Unbilled	**220**	30	–	190
Total kWh sales	**9,908**	126	1.3	9,782

PEF's revenues, excluding fuel and other pass-through revenues of $608 million and $645 million for the three months ended March 31, 2008 and 2007, respectively, increased $22 million. The increase in revenues was primarily due to base rate increases and increased wholesale revenues, partially offset by unfavorable retail customer growth and usage. The increase in base rates was $19 million; Hines 4 being placed in service contributed $10 million in additional revenues and the transfer of Hines 2 cost recovery from the fuel clause to base rates contributed $9 million. These base rate changes occurred in accordance with PEF's most recent base rate agreement. Wholesale revenues, excluding fuel and other pass-through revenues increased $8 million primarily due to two new contracts with one major customer and a contract amendment with another major customer. In accordance with the contracts' terms, the full financial impact of the new and amended contract changes will not be realized until later in 2008. PEF's base rate and wholesale revenue favorability was partially offset by the unfavorable retail customer growth and usage impact of $7 million.

PEF believes that the decline in general economic conditions, including weakness in the housing markets in both Florida and the United States, has contributed to a slowdown in customer growth and usage in its service territory. In addition to lower average usage per customer, PEF experienced significantly lower customer growth in the first quarter of 2008 than had been experienced in recent periods. PEF's average number of net customers for the three months ended March 31, 2008, compared to the same period in 2007 increased 7,000 customers. In comparison, PEF's average number of net customers for the three months ended March 31, 2007, compared to the same period in 2006, increased 31,000 customers.

PEF has secured and is pursuing additional wholesale contracts that will mitigate, to a certain extent, the impact of lower retail revenues. PEF cannot predict whether or to what extent the trends of declining usage per customer and lower customer growth will continue to negatively impact retail revenues or, if they do continue, the extent to which increased wholesale revenues may offset such a negative impact.

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 from or refund to customers.

Fuel and purchased power expenses were $524 million for the three months ended March 31, 2008, which represents a $24 million decrease compared to the same period in 2007. Fuel used in electric generation decreased $44 million to $341 million compared to the same period in 2007. This decrease was due to lower deferred fuel expense of $88 million, partially offset by increased current year fuel costs of $44 million. The lower deferred fuel expense was primarily due to the regulatory approval to lower the fuel factor for customers effective January 2008 as a result of over-recovery of fuel costs in the prior year. The increase in current year fuel costs was primarily due to a change in generation mix as a percentage of generation supplied by natural gas in response to plant outages and higher system requirements. Purchased power costs were $20 million higher for the three months ended March 31, 2008, due to increased current year purchases of $19 million as a result of higher fuel costs.

Operation and Maintenance

Operation and maintenance expenses (O&M) were $203 million for the three months ended March 31, 2008, which represents a $28 million increase when compared to the same period in 2007. O&M expenses increased $26 million related to an increase in storm damage reserves, which began in August 2007 and will continue through August 2008, and $3 million related to higher outage restoration, partially offset by a $5 million sales and use tax audit adjustment and $4 million lower environmental cost recovery (ECRC) costs due to deferral of expenses. The storm damage reserve and ECRC expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings.

Depreciation and Amortization

Depreciation and amortization expense was $76 million for the three months ended March 31, 2008, which represents a $21 million decrease compared to the same period in 2007. Depreciation and amortization expense decreased $26 million due to lower amortization of unrecovered storm restoration costs, partially offset by the impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a cost-recovery clause and, therefore, have no material impact on earnings.

Total Other Income

Total other income of $18 million increased $10 million for the three months ended March 31, 2008, compared to the same period in 2007, primarily due to $11 million favorable AFUDC equity related to costs associated with large construction projects. We expect AFUDC equity to continue to increase for the remainder of 2008, primarily due to increased spending on environmental initiatives and other large construction projects.

Total Interest Charges, net

Total interest charges, net were $44 million for the three months ended March 31, 2008, which represents a $7 million increase compared to the same period in 2007. The increase was primarily due to $9 million higher interest as a result of higher average debt outstanding, partially offset by $3 million favorable AFUDC debt related to costs associated with large construction projects.

Income Tax Expense

Income tax expense increased $2 million for the three months ended March 31, 2008, compared to the same period in 2007, primarily due to the $3 million tax impact of higher pre-tax income compared to the prior year, $1 million prior year changes in tax estimates and the $1 million impact of tax levelization, discussed below, partially offset by the $4 million impact of the increase in AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense. GAAP requires companies to apply a levelized effective tax rate to interim periods that is consistent with the estimated annual effective tax rate. PEF's income tax expense was increased by $1 million for the three months ended March 31, 2008 compared to no impact for the three months ended March 31, 2007, in order to maintain an effective tax rate consistent with the estimated annual rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Therefore, this adjustment will vary each quarter, but will have no effect on net income for the year.

CORPORATE AND OTHER

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. Corporate and Other expense is summarized below:

	Three Months Ended March 31,	
(in millions)	**2008**	2007
Other interest expense	**$ (54)**	$ (48)
Contingent value obligations	**–**	1
Tax levelization	**(1)**	(3)
Other income tax benefit	**17**	22
Other	**(1)**	(6)
Corporate and Other after-tax expense	**$ (39)**	$ (34)

Other interest expense increased $6 million for the three months ended March 31, 2008, compared to the same period in 2007. The increase for the three months ended March 31, 2008, was primarily due to an $8 million decrease in the interest allocated to discontinued operations. The decrease in interest expense allocated to discontinued operations resulted from the allocations of interest expense in early 2007 for operations that were sold later in 2007. Interest expense allocated to discontinued operations was $1 million and $9 million for the three months ended March 31, 2008 and 2007, respectively.

Progress Energy issued 98.6 million Contingent Value Obligations (CVOs) in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash flows the facilities generate. At March 31, 2008 and 2007, the CVOs had fair values of approximately $34 million and $31 million, respectively. We recorded an unrealized gain of $1 million for the three months ended March 31, 2007, and no adjustment for the three months ended March 31, 2008, to record the changes in fair value of the CVOs, which had average unit prices of $0.35 and $0.31 at March 31, 2008 and 2007, respectively.

GAAP requires companies to apply a levelized effective tax rate to interim periods that is consistent with the estimated annual effective tax rate. Income tax expense was increased by $1 million for the three months ended March 31, 2008, compared to an increase of $3 million for the three months ended March 31, 2007, in order to maintain an effective rate consistent with the estimated annual rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can also cause fluctuations in the effective tax rate for interim periods. Therefore, this adjustment will vary each quarter, but will have no effect on net income for the year.

Other income tax benefit decreased $5 million for the three months ended March 31, 2008, compared to the same period in 2007, primarily due to the tax impact of employee benefits.

Other decreased $5 million for the three months ended March 31, 2008, compared to the same period in 2007, primarily due to decreased legal expenses in 2008.

DISCONTINUED OPERATIONS

We divested multiple nonregulated businesses during 2008 and 2007 in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities.

TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale were used for general corporate purposes. As a result, during the three months ended March 31, 2008, we recorded an after-tax gain of $46 million on the sale of these assets.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Internal Revenue Code (the Code). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels were generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007. In accordance with FASB Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", operations must be abandoned prior to reporting them as discontinued operations. All periods have been restated to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Terminals and the synthetic fuels businesses collectively generated net earnings from discontinued operations of $12 million and $71 million for the three months ended March 31, 2008 and 2007, respectively. The decrease in net earnings from discontinued operations is primarily due to the 2007 expiration of the tax credit program.

CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 megawatts (MW) of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated loss of $226 million in December 2006. Based on the terms of the final agreement, during the quarter ended March 31, 2007, we reversed $16 million after-tax of the impairment recorded in 2006.

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represents substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represents the net cost to assign the Georgia Contracts and other related contracts. In the quarter ended June 30, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax. We used the net proceeds from these transactions for general corporate purposes.

CCO's operations generated net earnings from discontinued operations of $43 million for the three months ended March 31, 2007.

COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of approximately 30,000 acres in Lee County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. As a result of the sale, during the three months ended March 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets.

Net losses from discontinued operations for Coal Mining, excluding gain on disposal, were $6 million and $4 million for the three months ended March 31, 2008 and 2007, respectively.

OTHER DIVERSIFIED BUSINESSES

On October 2, 2006, we sold our natural gas drilling and production business (Gas) to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $1 million during the three months ended March 31, 2007, primarily related to working capital adjustments.

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. During the three months ended March 31, 2008, we recorded an after-tax gain on disposal of $1 million in connection with reduction of guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners, LLC (SeeNote 13B). The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods.

Also included in discontinued operations are earnings from other fuels businesses of $1 million, net of tax, for the three months ended March 31, 2007.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Progress Energy, Inc. is a holding company and, as such, has no revenue-generating operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $2.6 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities, and the ability of the Utilities to pay dividends or repay funds to us. As discussed under “Future Liquidity and Capital Resources” below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized. Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities’ operations, including expenditures for environmental compliance. We rely upon our operating cash flow, substantially all of which is generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. 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 are not expected to materially affect net income.

As a registered holding company, we are subject to regulation by the Federal Energy Regulatory Commission (FERC), including for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and non-utility 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 non-utility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and non-utility money pools but cannot borrow funds.

Cash from operations, short-term and long-term debt, limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans, and proceeds from the sale of the remainder of our nonregulated businesses completed in the first quarter, are expected to fund capital expenditures and common stock dividends for 2008. For the fiscal year 2008, we anticipate realizing an aggregate amount of approximately $100 million from the sale of stock through these plans.

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 in Item 1A, “Risk Factors” in the 2007 Form 10-K.

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

HISTORICAL FOR 2008 AS COMPARED TO 2007

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 increased by $461 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The increase in operating cash flow was primarily due to a $252 million tax payment made in 2007 related to the sale of Gas; the settlement of $247 million of derivative receivables primarily related to derivative contracts for our former synthetic fuels businesses (see Note 9); and a $131 million impact from accounts payable, driven by the timing of purchases and payments to vendors at the Utilities. These impacts were partially offset by a $108 million decrease in collateral held associated with the synthetic fuels derivative contracts discussed above and an $82 million decrease in the recovery of fuel costs at PEF.

INVESTING ACTIVITIES

Net cash used by investing activities increased by $143 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. This is due primarily to a $147 million increase in capital expenditures for utility property, primarily due to a $137 million increase in environmental compliance spending at PEF and a $75 million increase in net purchases of short-term investments included in available-for-sale securities and other investments. These impacts were partially offset by a $65 million increase in proceeds from sales of discontinued operations and other assets, net of cash divested. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

During the three months ended March 31, 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds from the sale of Terminals and Coal Mining (see Notes 3A and 3C). During the three months ended March 31, 2007, proceeds from sales of discontinued operations and other assets primarily included working capital adjustments for Gas and the sale of poles at Progress Telecommunications Corporation.

FINANCING ACTIVITIES

Net cash used by financing activities increased by $41 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The change in cash used by financing activities was primarily due to the financing activities discussed below, $117 million in net short-term borrowings in 2007, and $85 million in cash distributions to minority interests of consolidated subsidiaries related settlement of Ceredo Synfuel LLC’s (Ceredo) synthetic fuels derivatives contracts (See Note 9).

On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.

On March 12, 2008, PEC and PEF amended their revolving credit agreements (RCA) with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC’s RCA is now scheduled to expire on June 28, 2011, and PEF’s RCA is now scheduled to expire on March 28, 2011.

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.650% Medium-Term Notes, Series D, due April 1, 2008 and the remainder was placed in temporary investments for general corporate use as needed.

On April 14, 2008, we amended our RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 3, 2008. Our RCA is now scheduled to expire on May 3, 2012.

At December 31, 2007, we had 500 million shares of common stock authorized under our charter, of which 260 million shares were outstanding. For the three months ended March 31, 2008 and 2007, respectively, we issued approximately 0.5 million shares and 1.5 million shares of common stock resulting in approximately $20 million and $65 million in proceeds. Included in these amounts were approximately 0.4 million shares and 0.2 million shares for proceeds of approximately $19 million and $11 million, respectively, to meet the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2008, there were no material changes in our "Capital Expenditures," "Other Cash Needs," "Credit Facilities," or "Credit Rating Matters" as compared to those discussed under LIQUIDITY AND CAPITAL RESOURCES in Item 7 to the 2007 Form 10-K, other than as described below and under "Credit Rating Matters", "Regulatory Matters and Recovery of Costs" and "Financing Activities."

The Utilities produce substantially all of our consolidated cash from operations. We expect that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels businesses, whose operations have been abandoned and reclassified to discontinued operations, have historically produced significant earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). These tax credits have yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At March 31, 2008, we have carried forward $837 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

With the exception of the proceeds in the first quarter of 2008 from the sale of Terminals and Coal Mining (See Notes 3A and 3C), the absence of cash flow resulting from divested businesses is not expected to impact our future liquidity or capital resources as these businesses in the aggregate have been largely cash flow neutral over the last several years.

Cash from operations plus availability under our credit facilities and shelf registration statements is expected to be sufficient to meet our requirements in the near term. To the extent necessary, we may also use limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. In the latter half of 2007, the short-term credit markets tightened, resulting in higher interest rate spreads and shorter durations. In the latter half of the first quarter of 2008, the market has improved; however, there has been volatility on commercial paper spreads. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing from our RCAs, issuing short-term floating rate notes, and/or issuing long-term debt.

Progress Energy has approximately $9.9 billion in outstanding debt. Only $860 million of our debt is insured. These bonds are obligations of the Utilities and are traded in the tax-exempt auction rate securities market. Ambac Assurance Corporation insures approximately $620 million of the bonds and XL Capital Assurance, Inc. insures the remaining $240 million. To date, auctions for the Utilities' bonds have seen an increase in the interest rates that are periodically reset at each auction. Since the downgrade of XL Capital Assurance, Inc. on February 7, 2008, by Moody's Investors Service, Inc. (Moody's) and on February 25, 2008, by Standard & Poor's Rating Services (S&P), we have seen additional market volatility and an increase in the reset interest rates for a portion of our tax-exempt bonds. If additional downgrades by Moody's or S&P occur, we could experience additional volatility in this market and the potential for higher rate resets. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

As discussed in “Capital Expenditures,” under LIQUIDITY AND CAPITAL RESOURCES and “Strategy” under INTRODUCTION in Item 7 to the 2007 Form 10-K and in “Other Matters – Environmental Matters” of this Form 10-Q, over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under “Other Matters – Increasing Energy Demand” will require the Utilities to make significant capital investments. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

The amount and timing of future sales of 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 immediately 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 corporate purposes.

At March 31, 2008, the current portion of our long-term debt was $1.197 billion, which we expect to fund with a combination of cash from operations, commercial paper borrowings and long-term debt.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, as further discussed in Note 4 and “Other Matters – Regulatory Environment”, and filings for recovery of environmental costs, as discussed in Note 12 and in “Other Matters – Environmental Matters” of this filing and in Note 21 and in “Other Matters – Regulatory Environment” and “Other Matters – Environmental Matters” of the 2007 Form 10-K may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources. Developments since our 2007 Form 10-K are discussed below.

PEC Pass-through Clause Cost Recovery

On April 30, 2008, PEC filed with the South Carolina Public Service Commission (SCPSC) for an increase in the fuel rate charged to its South Carolina ratepayers. PEC is asking the SCPSC to approve a $39 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. If approved, the increase would take effect July 1, 2008 and would increase residential electric bills by $5.86 per 1,000 kWh, or 6.1 percent, for fuel cost recovery. A hearing on the matter has been scheduled by the SCPSC for June 12, 2008. We cannot predict the outcome of this matter.

As discussed further in Note 4 and in “Other Matters – Regulatory Environment,” South Carolina and North Carolina state energy legislation that became law in 2007 may impact our liquidity over the long term. Among other provisions, these state energy laws provide mechanisms for recovery of certain baseload generation construction costs and expand annual fuel clause mechanisms so that additional costs may be recovered annually. PEC has begun implementing a series of demand-side management (DSM) and energy-efficiency programs and deferred an immaterial amount of implementation and program costs for future recovery. On April 29 and May 1, 2008, PEC filed for NCUC approval of a total of five DSM and energy-efficiency programs. We cannot predict the outcome of these filings or whether the proposed programs will produce the expected operational and economic results.

On December 21, 2007, the SCPSC issued an order granting PEC’s petition seeking authorization to create a deferred account for DSM and energy-efficiency expenses. As a result, PEC has deferred an immaterial amount of implementation and program costs through March 31, 2008, for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy-efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

On February 29, 2008, the North Carolina Utilities Commission (NCUC) issued an order adopting final rules for implementing North Carolina’s comprehensive energy legislation. Among other things, the order establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) clause will be set based on projected costs with true-up provisions.

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent as well as recovery of the wholesale portion of the terminated GridSouth project startup costs over five years. If approved by FERC, the new rates would be effective July 1, 2008, and PEC estimates the impact of the new rates will increase 2008 revenues by $6 million to $8 million. We cannot predict the outcome of this matter.

PEF Pass-through Clause Cost Recovery

On October 10, 2007, the Florida Public Service Commission (FPSC) issued an order requiring PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. Neither PEF nor Florida's Office of the Public Counsel (OPC) filed an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for Crystal River Units No. 4 and 5 coal-fired steam turbines (CR4 and CR5). PEF believes its coal procurement practices have been prudent. We anticipate that a hearing will be held on the 2006 and 2007 coal purchases in January 2009. We cannot predict the outcome of this matter.

On February 29, 2008, PEF filed a petition for recovery of costs incurred to uprate Crystal River Unit No. 3 Nuclear Plant (CR3) in 2007 and 2006 under Florida's comprehensive energy legislation and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. The FPSC is scheduled to vote on this matter by October 2008. We cannot predict the outcome of this matter.

On May 1, 2008, PEF filed with the FPSC for an increase in the capacity cost-recovery charge under the FPSC nuclear cost-recovery rule. PEF is asking the FPSC to approve a $25 million increase in the capacity cost recovery rate for costs associated with the CR3 uprate. If approved, the increase would take effect with the first billing cycle for 2009 and would increase residential electric bills by $0.70 per 1,000 kWh. Also included in this filing was a revision to the estimate provided in the need determination proceeding to include indirect costs, for a total original estimate of $439 million. After PEF's completion of a transmission study and additional engineering studies, the current project estimate is $364 million. A hearing on the matter has been scheduled by the FPSC for September 2008, and the FPSC is scheduled to vote on this matter by October 2008. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers which were estimated to be $27 million at March 31, 2008. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) through the ECRC (see "Other Matters – Environmental Matters" for discussion regarding CAMR). The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $1.2 billion to $2.2 billion.

Nuclear Cost Recovery

The FPSC approved new rules on February 13, 2007, that allow PEF to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility.

As discussed further in Note 4 and "Other Matters – Nuclear", on March 11, 2008, PEF filed a petition for an affirmative Determination of Need for its proposed Levy Units 1 and 2 nuclear power plants, together with the associated facilities, including transmission lines and substation facilities. The filed, non-binding project cost estimate for Levy Units 1 and 2 is approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. A public hearing is scheduled for May 21-23, 2008, and a vote by the FPSC is scheduled for July 15, 2008. On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of the proposed Levy nuclear project. PEF filed the petition to assist the FPSC in the timely and adequate review of the projects costs recoverable under the FPSC nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009. Additionally, the filing included site selection costs of $38 million. Subsequent to an affirmative determination of need from the FPSC on the Levy nuclear project, PEF intends to file a formal petition to recover all prudently incurred costs under the FPSC nuclear cost-recovery rule. A decision by the FPSC on PEF's 2008 cost-recovery filing is expected on or before October 1, 2008. We cannot predict the outcome of these matters.

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." 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 standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At March 31, 2008, we have issued $416 million of guarantees for future financial or performance assurance, including $11 million at PEC and $2 million at PEF. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 14). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At March 31, 2008, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations (See Note 13B).

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 9 and Item 3, "Quantitative and Qualitative Disclosures about Market Risk" of this Form 10-Q, for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

As part of our ordinary course of business, we enter into various long- and short-term contracts for fuel requirements at our generating plants. Through March 31, 2008, contracts procured though our subsidiaries have increased our aggregate purchase obligations for fuel and purchased power by $4.287 billion from $17.644 billion, as stated in Note 22A in the 2007 Form 10-K. In March 2008, PEC issued long-term debt totaling $325 million. These increases are discussed under "PEC" and "PEF" below.

PEC

Through March 31, 2008, PEC's fuel and purchase power commitments increased by $3.248 billion from $5.078 billion, as stated in Note 22A in the 2007 Form 10-K. This increase is primarily related to coal purchase commitments, of which approximately $2 billion will be incurred through 2012, with the remainder incurred through 2018.

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038 (See Note 6).

PEF

Through March 31, 2008, PEF's fuel and purchase power commitments increased by $1.039 billion from $12.566 billion, as stated in Note 22A in the 2007 Form 10-K. Approximately $640 million of this increase is due to coal purchase commitments, of which approximately $191 million will be incurred through 2012, with the remainder incurred through 2018. Additionally, approximately $470 million of the increase will be incurred in the period 2014 through 2027 and is due to the impact of rising natural gas prices under a long-term gas supply agreement that was entered into in December 2004. Payments under this agreement are based on a published market price index. Contractual obligations under this contract are based on estimated future market prices.

OTHER MATTERS

SYNTHETIC FUELS TAX CREDITS

Prior to 2008, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualified for federal income tax credits so long as certain requirements were 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 fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year were phased out when annual average market prices for crude oil exceeded certain prices. Synthetic fuels were generally not economical to produce and sell absent the credits. The synthetic fuels tax credit program expired at the end of 2007.

TAX CREDITS

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K) effective January 1, 2006. 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 carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removed the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period.

Total Section 29/45K credits generated through December 31, 2007 (including those generated by Florida Progress prior to our acquisition), were $1.891 billion. As of March 31, 2008, $1.054 billion had been used to offset regular federal income tax liability and $837 million is being carried forward as deferred tax credits.

IMPACT OF CRUDE OIL PRICES

Section 29 provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (Annual Average Price) exceeded the Threshold Price, the amount of Section 29/45K tax credits were reduced for that year. Also, if the Annual Average Price exceeded the price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits are fully eliminated (Phase-out Price), the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation.

When the Annual Average Price fell between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits were reduced depended on where the Annual Average Price fell in that continuum. The Department 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 2007 was published on April 1, 2008. Based on the Annual Average Price for calendar year 2007 of $66.52, our $205 million of synthetic fuels tax credits generated during 2007 were reduced by 67 percent, or approximately $138 million.

In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production and was marked-to-market with changes in fair value recorded through earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed below in "Sales of Partnership Interests" and in Notes 1C and 3F, we disposed of our 100 percent ownership interest in Ceredo in March 2007. For the three months ended March 31, 2007, we recorded net pre-tax gains of $45 million related to these contracts, including $15 million attributable to Ceredo, of which less than $1 million was attributed to minority interest for the portion of the gain subsequent to disposal. The derivative contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact on 2008 earnings.

SALES OF PARTNERSHIP INTERESTS

In March 2007, we disposed of, through our subsidiary Progress Fuels, our 100 percent ownership interest in Ceredo, a subsidiary that produced and sold qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a non-recourse note receivable of $54 million. Payments on the note were received as we produced and sold qualifying coal-based solid synthetic fuels on behalf of the buyer. We received final payment on the note related to 2007 production of $5 million during the quarter ended March 31, 2008. The total amount of the proceeds was subject to adjustment once the final value of the 2007 Section 29/45K credits was known. This adjustment resulted in a $7 million reduction of the purchase price during the three months ended March 31, 2008. For the quarter ended March 31, 2008, we recorded gains on disposal of $5 million based on the value of the 2007 Section 29/45K tax credits. The operations of Ceredo were reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51", but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact from Ceredo's operations, which ceased as of December 31, 2007. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer, which reduces any gain. The ultimate resolution of these matters could result in adjustments to the gain on disposal in future periods. See Note 3F for additional discussion of this transaction and Note 13B for a general discussion of guarantees.

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of our coal-based solid synthetic fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. Gain recognition was dependent on the synthetic fuels production qualifying for Section 29/45K tax credits and the value of such tax credits as discussed above. Due to the impact on production from the 2007 permanent cessation of the synthetic fuels facilities and pursuant to the terms of the sales agreements, in January 2008, the purchasers abandoned their interests in Colona. Through March 31, 2008, there has been no material impact as a result of the abandonment.

See Note 13C for additional discussion related to our synthetic fuels operations.

REGULATORY ENVIRONMENT

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and other federal and state agencies common to the utility business. 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 one or more of these governmental agencies.

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail ratepayers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate when, or if, any of these states will move to increase retail competition in the electric industry.

The retail rate matters affected by state regulatory authorities are discussed in detail in Notes 4A and 4B. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

During the 2008 session, the Florida legislature passed comprehensive energy legislation, which will become law upon signature by the governor, which we expect will occur before the end of this summer. The legislation includes provisions that would, among other things, (1) help enhance the ability to cost-effectively site transmission lines; (2) require the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification in 2009; (3) direct the Florida Department of Environmental Protection (FDEP) to develop rules establishing a cap and trade program to regulate greenhouse gas emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification by the legislature; and (4) establish a new Florida Energy and Climate Commission as the principal governmental body to develop energy and climate policy for the State and to make recommendations to the governor and legislature on energy and climate issues.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law includes provisions for renewable energy portfolio standards, expansion of the definition of the traditional fuel clause and recovery of the costs of new DSM and energy-efficiency programs through an annual DSM clause.

On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina’s comprehensive energy legislation. These rules provide filing requirements associated with the legislation. The order requires PEC to submit its first annual REPS compliance plan by September 1, 2008, as part of its integrated resource plan. Under the new rules, beginning in 2009, PEC will also be required to file an annual REPS compliance report demonstrating the actions it has taken to comply with the REPS requirement. The rules measure compliance with the REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC will pursue a third-party REC tracking system, but will not develop or require participation in a REC trading platform at this time. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the REPS clause will be set based on projected costs with true-up provisions. On April 29 and May 1, 2008, PEC filed for NCUC approval of a total of five DSM and energy-efficiency programs, including the EnergyWise™ and distribution system demand response programs discussed below.

On April 29, 2008, PEC filed for approval by the NCUC of its EnergyWise™ program, which is a residential program that offers customers an incentive to permit PEC to remotely adjust central air conditioning and heat pumps in PEC’s eastern control area and electric resistance heating and water heaters in PEC’s western control area in order to duce peak demand. PEC’s goal for EnergyWise™ is to have the capability to reduce peak electricity demand by 200 MW by 2017.

Also on April 29, 2008, PEC filed for NCUC approval of its distribution system demand response program, which will provide additional capability for reducing and shifting peak electricity demand. The program also will reduce the level of natural electricity loss experienced over long distribution feeder lines, thereby eliminating the need for additional power generation to compensate for the line losses. PEC anticipates that the program will require an investment of approximately $260 million over five years and is expected to reduce peak demand by 250 MW. This distribution system investment is part of PEC’s broader “Smart Grid” strategy and is expected to provide a foundation for additional initiatives, including enhanced system reliability (through faster outage isolation and response) and new capabilities for incorporating renewable energy resources and other distributed generation into PEC’s energy mix. Such costs are expected to be recovered under the provisions of the North Carolina comprehensive energy legislation.

We cannot predict the outcome of the April 29 and May 1, 2008 filings or whether the proposed programs will produce the expected operational and economic results.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first Southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions.

Among other things, the executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007 that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers, who generate electricity from on-site renewable technologies of up to 1 MW in capacity, to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity (net metering). The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy efficiency and conservation measures, implementation of a climate registry, and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The FDEP held its first workshop on the greenhouse gas emissions cap on August 22, 2007, but we anticipate drafts of the rule to be issued later in 2008. We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Increasing Energy Demand", includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

LEGAL

We are subject to federal, state and local legislation and court orders. The specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures are discussed in detail in Note 13C.

INCREASING ENERGY DEMAND

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

We are actively pursuing expansion of our energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. Our energy-efficiency program provides simple, low-cost ways for residential customers to reduce energy use, promotes home energy checks, provides tools and programs for large and small businesses to minimize their energy use and provides an interactive internet Web site with online calculators, programs and efficiency tips.

We are actively engaged in a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants. While we pursue expansion of energy- efficiency and conservation programs, PEC has announced a two-year moratorium on constructing new coal-fired plants and that if PEC goes ahead with a new nuclear plant, the new plant would not be online until at least 2018 (see "Nuclear" below).

As authorized under Energy Policy Act of 2005 (EPACT), on October 4, 2007, the United States Department of Energy (DOE) published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects. In 2008, Congress authorized $38.5 billion in loan guarantee authority for innovative energy projects. Of the total provided, $18.5 billion is set aside for nuclear power facilities, $2 billion for advanced nuclear facilities for the "Front-end" of the nuclear fuel cycle, $10 billion for renewable and/or energy efficient systems and manufacturing and distributed energy generation/transmission and distribution, $6 billion for coal-based power generation and industrial gasification at retrofitted and new facilities that incorporate carbon capture and sequestration or other beneficial uses of carbon and $2 billion for advanced coal gasification. We cannot predict if we will pursue these loan guarantees.

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 take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved.

On November 14, 2006, PEC filed an application with the NRC for a 20-year extension of the Shearon Harris Nuclear Plant (Harris) operating license. The license renewal application for Harris is currently under review by the NRC with a decision expected in 2008.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications.

We previously announced that we are pursuing development of combined license (COL) applications to potentially construct new nuclear plants in North Carolina and Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC’s application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 18, 2008, the NRC docketed, or accepted for review, the Harris application. Docketing the application does not preclude additional requests for information as the review proceeds; nor does it indicate whether the NRC will issue the license. The NRC will publish in the near future an opportunity to intervene in the adjudicatory hearing required for this application. Petitions to intervene in a hearing may be filed within 60 days of the notice, by anyone whose interest may be affected by the proposed license and who wishes to participate as a party in the proceeding. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, the new plant would not be online until at least 2018 (See “Increasing Energy Demand” above).

On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF’s application submission. PEF expects to file the application for the COL in 2008. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, safety-related construction activities could begin as early as 2012, and a new plant could be online in 2016 (See “Increasing Energy Demand” above). In 2007, PEF completed the purchase of approximately 5,000 acres for the Levy County site and associated transmission needs. PEF filed a Determination of Need petition with the FPSC on March 11, 2008. The hearing is scheduled for May 21-23, 2008, and a vote by the FPSC is scheduled for July 15, 2008. We cannot predict the outcome of this matter.

In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF’s requests to change the comprehensive land use plan. The Florida Department of Community Affairs (FDCA) reviewed the proposed changes to the comprehensive land use plan and in their report, the FDCA expressed concerns related to the intensity of use and environmental suitability for some of the proposed amendments impacting PEF’s proposed Levy County nuclear site. We anticipate that the Levy County Planning

Commission will resolve the FDCA's concerns without impact to the potential project schedule. We cannot predict the outcome of this matter.

In addition, PEF expects to file its application for Site Certification with the FDEP in the second quarter of 2008. A decision on PEF's FDEP Site Certification Application is expected in 2009.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of the proposed Levy nuclear project. PEF filed the petition to assist the FPSC in the timely and adequate review of the projects costs recoverable under the FPSC nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009. Additionally, the filing included site selection costs of $38 million. Subsequent to an affirmative determination of need from the FPSC on the Levy nuclear project, PEF intends to file a formal petition to recover all prudently incurred costs under the FPSC nuclear cost-recovery rule. A decision by the FPSC on PEF's 2008 cost-recovery filing is expected on or before October 1, 2008. We cannot predict the outcome of this matter.

On April 7, 2008, PEF signed a letter of intent with the Shaw Group Inc. and Westinghouse Electric Co. to complete negotiations toward an engineering, procurement and construction (EPC) contract for up to two Westinghouse AP1000 nuclear reactors planned for construction at the Levy County, Fla. site. The letter of intent authorizes the purchase of long lead time materials for the reactors. At this time, no definitive decisions have been made to construct new nuclear plants.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per 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 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the Internal Revenue Service (IRS) provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

In accordance with provisions of Florida's comprehensive energy legislation enacted in 2006, the FPSC ordered new rules in December 2006 that would allow investor-owned utilities such as PEF to request recovery of certain planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

In 2007, the South Carolina legislature ratified new energy legislation, which includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. In 2007, the North Carolina legislature also passed new energy legislation, which authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. 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 frequently change and the ultimate costs of compliance cannot be precisely estimated.

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, the state of Florida or potentially responsible parties (PRP) groups. 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 PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 4 and 12). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. Hazardous and solid waste management matters are discussed in detail in Note 12A.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated in accordance with GAAP. 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 could change and additional losses, which could be material, may be incurred in the future.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which would likely result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxides (NOx), sulfur dioxide (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 pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAVR and mercury regulation, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described below. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. PEC has completed installation of controls to meet the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) requirements. The NOx SIP Call is not applicable to Florida. Expenditures for the NOx SIP Call include the cost to install NOx controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. The air quality controls installed to comply with the NOx SIP Call and Clean Smokestacks Act will result in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. The timing and extent of the costs for future projects will depend upon final compliance strategies.

Progress Energy

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through March 31, 2008
Clean Smokestacks Act	2002–2013	$1,500 – 1,600	$919
CAIR/CAVR/mercury regulation	2005–2016	1,300 – 2,400	492
Total air quality		2,800 – 4,000	1,411
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$2,800 – 4,000	$1,411

PEC

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through March 31, 2008
Clean Smokestacks Act	2002–2013	$1,500 – 1,600	$919
CAIR/CAVR/mercury regulation	2005–2016	100 – 200	13
Total air quality		1,600 – 1,800	932
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$1,600 – 1,800	$932

PEF

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through March 31, 2008
CAIR/CAVR/mercury regulation	2005–2016	$1,200 – 2,200	$479
Clean Water Act Section 316(b) (a)		–	–
Total air and water quality		$1,200 – 2,200	$479

(a) Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."

To date, under the first phase of Clean Smokestacks Act emission reductions, all environmental compliance projects at PEC's Asheville and Lee plants and several projects at PEC's Roxboro plant have been placed in service. The remaining projects at PEC's two largest plants, Roxboro and Mayo, are under construction and are expected to be completed in 2008 and 2009, respectively. The remaining projects to comply with the second phase of emission reductions, which are smaller in scope, have not yet begun. These estimates are conceptual in nature and subject to change. As discussed below, our Clean Smokestacks Act compliance costs have increased from December 31, 2007.

To date, expenditures at PEF for CAIR/CAVR/mercury regulation primarily relate to environmental compliance projects under construction at CR5 and CR4, which are expected to be placed in service in 2009 and 2010, respectively. See discussion of projects for Crystal River Units No. 1 and No. 2 to meet CAVR beyond-BART requirements below. As a result of changes in the scope of work related to CAIR and the court decision that vacated the delisting determination and the Clean Air Mercury Rule (CAMR) discussed below, our estimated costs have decreased from December 31, 2007. Our current estimated costs reflect only the completion of engineering and design work in progress at the time that the CAMR was vacated. Compliance plans and estimated costs to meet the requirements of new mercury regulations will be determined when those new regulations are finalized.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (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 has undertaken civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities, several of which were 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.

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 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In March 2008, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.5 billion to $1.6 billion at the time of the filing. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million 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, increases in the estimated inflation factor applied to future project costs, and the impact of additional planning for Sutton Unit No. 3 and Cape Fear Units No. 5 and No. 6. We are continuing to evaluate various design, technology and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the equipment. Recent legislation in North Carolina and South Carolina expanded the traditional fuel clause to include the annual recovery of reagents and certain other costs; all other O&M expenses are currently recoverable through base rates. On March 23, 2007, PEC filed a petition with the NCUC regarding future recovery of costs to comply with the Clean Smokestacks Act, and on October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, Carolina Utility Customers Association (CUCA) and Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC’s proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis. See further discussion about the Clean Smokestacks Act in Note 4A. We cannot predict the outcome of this matter.

Two of PEC’s largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. In 2005, PEC entered into an agreement with the joint owner to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 12B).

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 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. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule

On March 10, 2005, the EPA issued the final CAIR. The EPA’s rule requires the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, 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. States were required to adopt rules implementing the CAIR and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR in 2007.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies 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. On March 25, 2008 the D. C. Court of Appeals heard oral arguments in the litigation on the CAIR. The outcome of this matter cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that set mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encouraged a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. Sixteen states subsequently petitioned for a review of the EPA’s determination confirming the delisting. On February 8, 2008, the U.S. Court of

Appeals for the District of Columbia (D.C. Court of Appeals) decided in favor of the petitioners and vacated the delisting determination and the CAMR. On March 24, 2008, the EPA and the Utility Air Regulatory Group filed petitions for rehearing by the full court of appeals. The three states in which the Utilities operate adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR and the petitions for rehearing will affect the state rules. The outcome of this matter cannot be predicted.

On June 15, 2005, the EPA issued the final 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, including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. The reductions associated with BART begin in 2013. 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. Plans for compliance with CAIR and mercury regulation may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that requires sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, Bartow Unit No. 3 and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted.

PEC and PEF are each developing an integrated compliance strategy to meet all the requirements of the CAIR, CAVR and mercury regulation. We are evaluating various design, technology and new generation options that could change PEC's and PEF's costs to meet these requirements.

The integrated compliance strategy PEF anticipates implementing should provide most, but not all, of the NOx reductions required by CAIR. Therefore, PEF anticipates utilizing the cap-and-trade feature of CAIR by purchasing annual and seasonal NOx allowances. Because the emission controls cannot be installed in time to meet CAIR's NOx requirements in 2009, PEF anticipates purchasing a higher level of annual and seasonal allowances in that year. The costs of these allowances would depend on market prices at the time these allowances are purchased. PEF expects to recover the costs of these allowances through its Environmental Cost Recovery Clause (ECRC).

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, CAMR and CAVR through the ECRC (see discussion above regarding CAMR). On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy. On June 1, 2007, PEF filed a supplemental petition for approval of its compliance plan and associated contracts and recovery of costs for air pollution control projects, which included approximately $1.0 billion to $2.3 billion of estimated capital costs for the range of alternative plans. The estimated capital cost for the recommended plan, which was $1.26 billion in the June 1, 2007 filing, represents the low end of the range in the table of estimated required environmental expenditures shown above. On April 2, 2008, PEF filed a petition for approval true-up of final environmental costs for the period January 2007 to December 2007 and a review of the integrated clean air compliance plan, which reconfirmed the efficacy of the recommended plan. The difference in costs between the recommended plan and the high end of the range represents the additional costs that may be incurred if pollution controls are required on Crystal River Units No. 1 and No. 2 in order to comply with the requirements of CAVR beyond BART, should reasonable progress in improving visibility not be achieved, as discussed above. The increase from the estimates filed in March 2006 is primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. 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 March 16, 2006, the EPA issued a final 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. On June 26, 2006, the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's final action on the petition. This case is being held in abeyance until the challenges to the CAIR have been resolved. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On December 21, 2005, the EPA announced proposed changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter (PM 2.5) 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 (PM 2.5-10). The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter (PM 10). On September 20, 2006, the EPA announced that it is finalizing the PM 2.5 NAAQS as proposed. In addition, the EPA decided not to establish a PM 2.5-10 NAAQS, and it is eliminating the annual PM 10 NAAQS, but the EPA is retaining the 24-hour PM 10 NAAQS. These changes are not expected to result in designation of any additional nonattainment areas in PEC's or PEF's service territories. On December 18, 2006, environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter. The outcome of this matter cannot be predicted.

On March 12, 2008, the EPA announced changes to the NAAQS for ground-level ozone. The EPA revised the 8-hour primary and secondary standards from 0.08 parts per million to 0.075 parts per million. Depending on air quality improvements expected over the next several years as current federal requirements are implemented, additional nonattainment areas may be designated in PEC's and PEF's service territories. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

Water Quality

1. General

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.

2. Section 316(b) of the Clean Water Act

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004. The July 2004 rule required assessment of the baseline environmental effect of withdrawal of cooling water and development of technologies and measures for reducing environmental effects by certain percentages. Additionally, the rule authorized establishment of alternative performance standards where the site-specific costs of achieving the otherwise applicable standards would have been substantially greater than either the benefits achieved or the costs considered by the EPA during the rulemaking.

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA. On July 9, 2007, the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitting authorities establish best available technology controls for minimizing adverse environmental impact at existing cooling water intake structures on a case-by-case, best professional judgment basis. On April 14, 2008, the U.S. Supreme Court agreed to review a portion of the U.S. Court of Appeals decision and hear arguments related to whether the EPA is authorized to compare costs with benefits in determining the "best technology available for minimizing adverse environmental impact" at cooling water intake structures. As a result of these recent developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

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. There are proposals and ongoing studies at the state and federal levels, including the state of Florida, to address global climate change that would regulate CO_2 and other greenhouse gases. See further discussion of the executive orders issued by the governor of Florida to address reduction of greenhouse gas emissions under "Other Matters – Regulatory Environment."

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 ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. 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 action on this important issue as discussed under "Other Matters – Increasing Energy Demand." In addition to a report issued in 2006, we will issue an updated report on global climate change in the second quarter of 2008, which further evaluates this dynamic issue. 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.

In a decision issued July 15, 2005, the D.C. Court of Appeals denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation. The U.S. Supreme Court agreed to hear the case and on April 2, 2007, it ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. On April 2, 2008, 18 states and 11 environmental groups filed an action in the D. C. Circuit Court against the EPA Administrator seeking an order requiring EPA to make a determination within 60 days of whether greenhouse gas emissions endanger public health and welfare. The impact of these developments cannot be predicted.

NEW ACCOUNTING STANDARDS

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

PEC

The following MD&A 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 "Safe Harbor for Forward-Looking Statements" included within this Form 10-Q and Item 1A, "Risk Factors" to the 2007 Form 10-K for a discussion of the factors that may impact any such forward-looking statements made herein.

RESULTS OF OPERATIONS

This information is incorporated herein by reference to "Results of Operations" in Progress Energy's MD&A, insofar as it relates to PEC.

LIQUIDITY AND CAPITAL RESOURCES

This information is incorporated herein by reference to "Liquidity and Capital Resources" in Progress Energy's MD&A, insofar as it relates to PEC.

Cash provided by operating activities increased $209 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The increase in operating cash flow was primarily due to a $92 million impact from increases in accounts payable and payables to affiliated companies; $53 million due to income tax impacts; a $25 million impact due to lower wholesale billings; and a $16 million impact from inventory, primarily due to lower coal inventory purchases. The increase in accounts payable and payables to affiliated companies was primarily driven by the timing of purchases and payments to vendors and affiliates.

Cash used by investing activities increased $137 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The increase in cash used in investing activities was primarily due to a $109 million increase in advances to affiliates and a $50 million decrease in net proceeds from short-term investments included in available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts. These impacts were partially offset by a $35 million decrease in capital expenditures for utility property additions, primarily driven by lower spending for compliance with the Clean Smokestacks Act.

Net cash provided by financing activities was $164 million for the three months ended March 31, 2008, compared to net cash used by financing activities of $26 million for the three months ended March 31, 2007, for a net increase of $190 million. The increase in cash provided by financing activities was due primarily to a $325 million long-term debt issuance, partially offset by a $154 million decrease related to advances from affiliates. PEC's 2008 financing activities are further described under Progress Energy's MD&A, "Liquidity and Capital Resources".

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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 9 and Item 3, "Quantitative and Qualitative Disclosures about Market Risk" of this Form 10-Q, for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

This information is incorporated herein by reference to "Contractual Obligations" in Progress Energy's MD&A, insofar as it relates to PEC.

OTHER MATTERS

This information is incorporated herein by reference to “Other Matters” in Progress Energy’s MD&A, insofar as it relates to PEC.

PEF

The following MD&A 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 “Safe Harbor for Forward-Looking Statements” included within this Form 10-Q and Item 1A, “Risk Factors” to the 2007 Form 10-K for a discussion of the factors that may impact any such forward-looking statements made herein.

Other than as discussed below, the information called for by Item 2 is omitted pursuant to Instruction H(2)(c) to Form 10-Q (Omission of Information by Certain Wholly Owned Subsidiaries).

RESULTS OF OPERATIONS

This information is incorporated herein by reference to “Results of Operations” in Progress Energy’s MD&A, insofar as it relates to PEF.

LIQUIDITY AND CAPITAL RESOURCES

This information is incorporated herein by reference to “Liquidity and Capital Resources” in Progress Energy’s MD&A, insofar as it relates to PEF.

Cash provided by operating activities decreased $39 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The decrease was primarily due to an $82 million decrease in the recovery of fuel costs, a $32 million increase in NOx and SO_2 emission allowance purchases, and a $10 million decrease from accounts receivable and receivables from affiliated companies. These impacts were partially offset by a $90 million increase from accounts payable and payables to affiliated companies primarily driven by the timing of purchases and payments to vendors and affiliates.

Cash used in investing activities increased $7 million for the three months ended March 31, 2008, when compared to the corresponding period in the prior year. The increase in cash used in investing activities was primarily due to a $185 million increase in capital expenditures for utility property additions, primarily due to a $137 million increase in environmental compliance spending. This impact was partially offset by a $149 million decrease in advances to affiliates and a $23 million decrease in nuclear fuel additions.

Net cash provided by financing activities was $14 million for the three months ended March 31, 2008, compared to net cash used by financing activities of $36 million for the three months ended March 31, 2007, for a net increase of $50 million. The increase in cash provided by financing activities was due primarily to a $131 million change in advances from affiliates, partially offset by the payment at maturity of $80 million in first mortgage bonds. PEF’s 2008 financing activities are further described under Progress Energy’s MD&A, “Liquidity and Capital Resources”.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

PEF’s off-balance sheet arrangements and contractual obligations are described below.

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 9 and Item 3, “Quantitative and Qualitative Disclosures about Market Risk” of this Form 10-Q, for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

This information is incorporated herein by reference to “Contractual Obligations” in Progress Energy’s MD&A, insofar as it relates to PEF.

OTHER MATTERS

This information is incorporated herein by reference to “Other Matters” in Progress Energy’s MD&A, insofar as it relates to PEF.

ITEM 3. 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 9).

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" to the 2007 Form 10-K and "Safe Harbor for Forward-Looking Statements" included within this Form 10-Q for a discussion of the factors that may impact any such forward-looking statements made herein.

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

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

PROGRESS ENERGY

Other than described below, the various risks that we are exposed to have not materially changed since December 31, 2007.

INTEREST RATE RISK

Our exposure to changes in interest rates from fixed rate and variable rate long-term debt at March 31, 2008, has changed from December 31, 2007. The total notional amount of fixed rate long-term debt at March 31, 2008, was $8.2 billion, with an average interest rate of 5.94% and fair market value of $8.5 billion. The total notional amount of fixed rate long-term debt at December 31, 2007, was $7.9 billion, with an average interest rate of 6.20% and fair market value of $8.2 billion. The total notional amount of variable rate long-term debt at March 31, 2008, was $1.4 billion, with an average interest rate of 4.27% and fair market value of $1.4 billion. The total notional amount of variable rate long-term debt at December 31, 2007, was $1.4 billion, with an average interest rate of 4.80% and fair market value of $1.4 billion.

In addition to our variable rate long-term debt, we typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. At March 31, 2008, and December 31, 2007, approximately 16 percent of consolidated debt was in floating rate mode, including interest rate swaps.

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 exposure in the transaction is the cost of replacing the agreements at current market rates. We only enter into interest rate derivative agreements 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 Instruments and Hedging Activities" (SFAS No. 133), interest rate derivatives that qualify as hedges are separated 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 summarize the terms, fair market values and exposures of our interest rate derivative instruments.

CASH FLOW HEDGES

At March 31, 2008, PEF had $200 million notional of pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions and at December 31, 2007, PEC had $200 million notional of pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions. Under terms of these swap agreements, we will pay a fixed rate and receive a floating rate based on the 3-month London Inter Bank Offering Rate (LIBOR). The Parent had no open interest rate cash flow hedges at March 31, 2008, and December 31, 2007.

Cash Flow Hedges *(dollars in millions)*	Notional Amount	Pay	Receive (a)	Fair Value	Exposure (b)
PEC					
Risk hedged at March 31, 2008	**None**				
Risk hedged at December 31, 2007					
Anticipated 10-year debt issue (c)	$100	5.32%	3-month LIBOR	$(5)	$(2)
Anticipated 30-year debt issue (d)	100	5.50%	3-month LIBOR	(7)	(4)
Total	$200	5.41%		$(12)	$(6)
PEF					
Risk hedged at March 31, 2008					
Anticipated 10-year debt issue (e)	**$100**	**4.52%**	**3-month LIBOR**	**$(3)**	**$(2)**
Anticipated 30-year debt issue (f)	**100**	**4.92%**	**3-month LIBOR**	**(4)**	**(4)**
Total	**$200**	**4.72%**		**$(7)**	**$(6)**
Risk hedged at December 31, 2007:	None				

(a) 3-month LIBOR rate was 2.69% at March 31, 2008, and 4.70% at December 31, 2007.

(b) Exposure indicates change in value due to 25 basis point unfavorable shift in interest rates.

(c) Anticipated 10-year debt issue hedges were terminated on March 10, 2008, in conjunction with PEC's issuance of $325 million 6.30% First Mortgage Bonds.

(d) Anticipated 30-year debt issue hedges were terminated on March 10, 2008, in conjunction with PEC's issuance of $325 million 6.30% First Mortgage Bonds.

(e) Anticipated 10-year debt issue hedge matures on June 30, 2018, and requires mandatory cash settlement on June 30, 2008.

[f] Anticipated 30-year debt issue hedge matures on June 30, 2038, and requires mandatory cash settlement on June 30, 2008.

On January 8, 2008, PEF entered into a 10-year $100 million notional forward starting swap and a 30-year $100 million notional forward starting swap to mitigate exposure to interest rate risk in anticipation of future debt issuances. On May 1, 2008, PEF entered into a $50 million notional 10-year forward starting swap and a $100 million notional 30-year forward starting swap to mitigate exposure to interest rate risk in anticipation of future debt issuances.

MARKETABLE SECURITIES PRICE RISK

At March 31, 2008, and December 31, 2007, the fair value of our nuclear decommissioning trust funds was $1.313 billion and $1.384 billion, respectively, including $771 million and $804 million, respectively, for PEC and $542 million and $580 million, respectively, for PEF. 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.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At March 31, 2008, and December 31, 2007, the fair value of CVOs was $34 million. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A hypothetical 10 percent increase in the March 31, 2008, market price would result in a $3 million increase 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, most of our long-term power sales contracts shift substantially all fuel price risk to the purchaser.

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify and are elected as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. At March 31, 2008, we did not have any derivative commodity instruments not eligible for recovery from ratepayers.

See Note 9 for additional information with regard to our commodity contracts and use of derivative financial instruments.

DISCONTINUED OPERATIONS

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. At December 31, 2007, the $234 million fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet. See Note 9A for additional discussion related to our commodity derivatives.

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.

The Utilities have derivative instruments related to their 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 on the Balance Sheets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. During the quarters ended March 31, 2008 and 2007, PEC recorded a net realized gain of less than $1 million. During the quarters ended March 31, 2008 and 2007, PEF recorded a net realized gain of $16 million and a net realized loss of $17 million, respectively.

The December 31, 2007 balances presented below reflect the retrospective adoption of FASB Staff Position No. FIN 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (See Note 2).

At March 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $13 million short-term derivative asset position included in prepayments and other current assets and $36 million long-term derivative asset position included in other assets and deferred debits on the PEC Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments were recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $4 million short-term derivative liability included in other current liabilities on the PEC Consolidated Balance Sheet. PEC had no cash collateral position at March 31, 2008 or December 31, 2007.

At March 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $204 million short-term derivative asset position included in current derivative assets, a $174 million long-term derivative asset position included in derivative assets, a $4 million short-term liability position included in derivative liabilities, and a $5 million long-term derivative liability position included in other liabilities and deferred credits on the PEF Balance Sheet. At December 31, 2007, the fair value of such instruments were recorded as a $83 million short-term derivative asset position included in current derivative assets, a $100 million long-term derivative asset position included in derivative assets, a $38 million short-term liability position included in derivative liabilities, and a $9 million long-term derivative liability position included in other liabilities and deferred credits on the PEF Balance Sheet. PEF had a $51 million cash collateral liability at March 31, 2008, included in other current liabilities on the PEF Balance Sheet, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

PEC designates 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 power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At March 31, 2008 and December 31, 2007, neither we nor the Utilities had material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for the three months ended March 31, 2008 and 2007.

At March 31, 2008 and December 31, 2007, the amount recorded in our or PEC's accumulated other comprehensive income related to commodity cash flow hedges was not material and PEF had no amount recorded in accumulated other comprehensive income related to commodity cash flow hedges.

PEC

The information required by this item is incorporated herein by reference to the "Quantitative and Qualitative Disclosures about Market Risk" discussed above insofar as it relates to 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. Other than as discussed above, PEC's exposure to these risks has not materially changed since March 31, 2008.

PEF

Other than as discussed above, the information called for by Item 3 is omitted pursuant to Instruction H(2)(c) to Form 10-Q (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 4. CONTROLS AND PROCEDURES

PROGRESS ENERGY

Pursuant to the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of management, including our Chairman, President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of our 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, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose 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 management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting during the quarter ended March 31, 2008, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 4. T CONTROLS AND PROCEDURES

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.

There has been no change in PEC’s internal control over financial reporting during the quarter ended March 31, 2008, 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, and with the participation of its management, including PEF’s Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEF’s disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEF’s Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by 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.

There has been no change in PEF’s internal control over financial reporting during the quarter ended March 31, 2008, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Legal aspects of certain matters are set forth in PART I, Item 1 (See Note 13C).

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors to the 2007 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in the 2007 Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

With the 2008 divestiture of Terminals and Coal Mining, we are no longer subject to operational and financial risks from operating nonregulated businesses as disclosed in the 2007 Form 10-K.

ITEM 2. UNREGISTERED SALE OF EQUITY SECURITIES AND USE OF PROCEEDS

RESTRICTED STOCK UNIT AWARD PAYOUTS

(a) Securities Delivered. On January 2, 2008, January 15, 2008 and January 24, 2008, 91 shares, 4,178 shares and 296 shares, respectively, of our common stock were delivered to certain former employees pursuant to the terms of the Progress Energy 2002 Equity Incentive Plan (EIP), which was approved by Progress Energy's shareholders on May 8, 2002. Additionally, on March 20, 2008, 170,516 shares of our common stock were delivered to certain current employees pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(b) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(c) Consideration. The restricted stock unit awards were granted to provide an incentive to the former employees to exert their utmost efforts on Progress Energy's behalf and thus enhance our performance while aligning the employees' interest with those of our shareholders.

(d) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, non-contributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

PERFORMANCE SHARE SUB-PLAN AWARD PAYOUTS

(a) Securities Delivered. On March 24, 2008, 360,674 shares of our common stock were delivered to employees pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(b) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(c) Consideration. The performance share awards were granted to provide an incentive to the former employees to exert their utmost efforts on Progress Energy's behalf and thus enhance our performance while aligning the employees' interest with those of our shareholders.

(d) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, non-contributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

ISSUER PURCHASES OF EQUITY SECURITIES FOR FIRST QUARTER OF 2008

Period	(a) Total Number of Shares (or Units) Purchased (1)(2)	(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)
January 1 – January 31	429,378	$46.2555	N/A	N/A
February 1 - February 29	70,000	43.9054	N/A	N/A
March 1 - March 31	–	–	N/A	N/A
Total	499,378	$45.9261	N/A	N/A

(1) At March 31, 2008, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.

(2) The plan administrator purchased 499,378 shares of our common stock in open-market transactions to meet share delivery obligations under our 401(k).

ITEM 5. OTHER INFORMATION

CONDENSED CONSOLIDATING STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

For informational purposes, we have corrected an error in the presentation of the condensed consolidating Statements of Income previously reported in Note 23 in the 2007 Form 10-K. The error related to the line items affiliate revenues and discontinued operations, net of tax in the Subsidiary Guarantor and the Other columns. Specifically, certain affiliate revenues of discontinued Terminals operations were incorrectly included in continuing operations. This resulted in misclassifications between income from continuing operations and discontinued operations, net of tax in the Subsidiary Guarantor column in the condensed consolidating Statements of Income for the years ended December 31, 2007, 2006 and 2005. There were equal and offsetting errors in the Other column, with no impact to the Parent or Progress Energy, Inc. columns. This correction is limited to the Subsidiary Guarantor and the Other columns in the condensed consolidating Statements of Income in Note 23 in the 2007 Form 10-K and does not affect Progress Energy's Consolidated Statements of Income, Consolidated Balance Sheets or Consolidated Statements of Cash Flows. We will prospectively present restated consolidating financial information the next time we issue our annual consolidated financial statements.

The following schedules present the specific line item amounts in Note 23 in the 2007 Form 10-K that have been restated as a result of this correction:

Condensed Consolidating Statement of Income
Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
As originally reported				
Affiliate revenues	$ –	$ 89	$ (89)	$ –
Total operating revenues	–	4,857	4,296	9,153
Operating (loss) income	(10)	679	877	1,546
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	528	694	1,036
Income (loss) from continuing operations	489	402	(198)	693
Discontinued operations, net of tax	15	(59)	(145)	(189)
As restated				
Affiliate revenues	$ –	$ –	$ –	$ –
Total operating revenues	–	4,768	4,385	9,153
Operating (loss) income	(10)	590	966	1,546
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	439	783	1,036
Income (loss) from continuing operations	489	313	(109)	693
Discontinued operations, net of tax	15	30	(234)	(189)

Condensed Consolidating Statement of Income
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
As originally reported				
Affiliate revenues	$ –	$ 41	$ (41)	$ –
Total operating revenues	–	4,678	4,046	8,724
Operating (loss) income	(14)	657	844	1,487
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	530	699	906
Income (loss) from continuing operations	579	340	(368)	551
Discontinued operations, net of tax	(8)	359	(331)	20
As restated				
Affiliate revenues	$ –	$ –	$ –	$ –
Total operating revenues	–	4,637	4,087	8,724

Operating (loss) income	(14)	616	885	1,487
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	489	740	906
Income (loss) from continuing operations	579	299	(327)	551
Discontinued operations, net of tax	(8)	400	(372)	20

Condensed Consolidating Statement of Income
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
As originally reported				
Affiliate revenues	$ –	$ 188	$ (188)	$ –
Total operating revenues	–	4,144	3,804	7,948
Operating (loss) income	(16)	664	740	1,388
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	500	580	825
Income (loss) from continuing operations	693	400	(570)	523
Discontinued operations, net of tax	4	(26)	195	173
As restated				
Affiliate revenues	$ –	$ –	$ –	$ –
Total operating revenues	–	3,956	3,992	7,948
Operating (loss) income	(16)	476	928	1,388
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	312	768	825
Income (loss) from continuing operations	693	212	(382)	523
Discontinued operations, net of tax	4	162	7	173

QUARTERLY FINANCIAL DATA FOR 2007 AND 2006

We have corrected an error in the presentation of the unaudited summarized financial data previously reported for Progress Energy in Note 24 in the 2007 Form 10-K. Specifically, the Progress Energy quarterly data reported for 2007 and 2006 contained misclassifications between income from continuing operations and income from discontinued operations relating to the impacts of quarterly tax levelization adjustments (See Note 1B). When the synthetic fuels businesses were reclassified to discontinued operations in the fourth quarter of 2007 (See Note 3A), the impacts of the quarterly tax levelization adjustments associated with the synthetic fuels tax credits were not also reclassified to discontinued operations. This correction is limited to amounts reported for Progress Energy only in Note 24 in the 2007 Form 10-K and does not affect the information presented in Note 24 for PEC and PEF. This correction does not affect our Consolidated Statements of Income for 2007 or 2006, as the quarterly tax levelization adjustments net to zero on an annual basis. In addition, this correction does not impact any previously filed Form 10-Q as the synthetic fuels businesses were first reclassified to discontinued operations in the fourth quarter of 2007.

The following schedules present specific line item amounts in Note 24 in the 2007 Form 10-K that have been restated as a result of this correction:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2007				
As originally reported				
Income from continuing operations	$ 159	$ 106	$ 327	$ 101
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.63	0.42	1.27	0.39
Diluted earnings per common share				
Income from continuing operations	0.62	0.41	1.27	0.39
As restated				
Income from continuing operations	149	138	311	95
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
Diluted earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
2006				
As originally reported				
Income from continuing operations	$ 67	$ 110	$ 268	$ 106
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
As restated				
Income from continuing operations	85	112	246	108
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.34	0.45	0.98	0.43
Diluted earnings per common share				
Income from continuing operations	0.34	0.45	0.98	0.43

ITEM 6. EXHIBITS

(a) Exhibits

Exhibit Number	Description	Progress Energy	PEC	PEF
10(a)	Executive and Key Manager 2008 Performance Share Sub-Plan, effective as of March 18, 2008, Exhibit A to the 2007 Equity Incentive Plan	X	X	X
10(b)	Form of Restricted Stock Unit Agreement as of March 18, 2008	X	X	X
31(a)	302 Certifications of Chief Executive Officer	X		
31(b)	302 Certifications of Chief Financial Officer	X		
31(c)	302 Certifications of Chief Executive Officer		X	
31(d)	302 Certifications of Chief Financial Officer		X	
31(e)	302 Certifications of Chief Executive Officer			X
31(f)	302 Certifications of Chief Financial Officer			X
32(a)	906 Certifications of Chief Executive Officer	X		
32(b)	906 Certifications of Chief Financial Officer	X		
32(c)	906 Certifications of Chief Executive Officer		X	
32(d)	906 Certifications of Chief Financial Officer		X	
32(e)	906 Certifications of Chief Executive Officer			X
32(f)	906 Certifications of Chief Financial Officer			X

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PROGRESS ENERGY, INC.

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

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

Date: May 9, 2008

(Registrants)

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 and Controller

Progress Energy, Inc.

Chief Accounting Officer

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.

Florida Power Corporation d/b/a Progress Energy Florida, Inc.

EXHIBIT A
TO
2007 EQUITY INCENTIVE PLAN

EXECUTIVE AND KEY MANAGER 2008 PERFORMANCE SHARE SUB-PLAN

This Executive and Key Manager 2008 Performance Share Sub-Plan ("Sub-Plan") sets forth rules and regulations adopted by the Committee for issuance of Performance Share Awards under Section 10 of the 2007 Equity Incentive Plan ("Plan"). This Sub-Plan shall apply to Awards granted effective on and after March 18, 2008. In addition, the rules and regulations relating to the deferral of Awards set forth in this Sub-Plan shall apply to any Awards which become vested on or after January 1, 2005. Capitalized terms used in this Sub-Plan that are not defined herein shall have the meaning given in the Plan. In the event of any conflict between this Sub-Plan and the Plan, the terms and conditions of the Plan shall control. No Award Agreement shall be required for participation in this Sub-Plan.

Section 1. Definitions

When used in this Sub-Plan, the following terms shall have the meanings as set forth below, and are in addition to the definitions set forth in the Plan. Defined terms used in this Sub-Plan and not defined below shall have the meanings set forth in the Plan.

1.1 "Account" means the account used to record and track the number of Performance Shares granted to each Participant as provided in Section 2.4.

1.2 "Award" as used in this Sub-Plan means each aggregate award of Performance Shares as provided in Section 2.2.

1.3 "Change of Control" means a change of control as defined for purposes of Section 409A of the Code.

1.4 "Disability" means disability as defined for purposes of Section 409A of the Code.

1.5 "Early Retirement" means Separation from Service after attaining age 55 and completing at least 10 years of service.

1.6 "Early Vesting Event" with respect to a Performance Award means the Participant's death, Disability, Retirement, or Separation from Service as a result of a Divestiture, or any of the vesting events provided in Section 3.2 in connection with a Change in Control.

1.7 "Normal Retirement" means Separation from Service on or after attaining age 65.

1.8 "Performance Period" for purposes of this Sub-Plan means three consecutive Years beginning with the Year in which an Award is granted.

1.9 “Performance Schedule” means Attachment 1 to this Sub-Plan, which sets forth the methodology for calculating the Performance Share Awards applicable to this Sub-Plan.

1.10 “Performance Share” for purposes of this Sub-Plan means each unit of an Award granted to a Participant, the value of which is equal to the value of Company Stock as hereinafter provided.

1.11 “Retire” or “Retirement” means Early Retirement or Normal Retirement.

1.12 “Salary” means the regular base rate of compensation payable by the Company to a Participant on an annual basis. Salary does not include bonuses, if any, or incentive compensation, if any. Such compensation shall not be reduced by any deferrals made under any other plans or programs maintained by the Company.

1.13 “Section 409A” means Section 409A of the Code, or any successor section under the Code, as amended and as interpreted by final or proposed regulations promulgated thereunder from time to time.

1.14 “Separation from Service” means separation from service with the Company as defined for purposes of Section 409A of the Code.

1.15 “Total Business Return” means the average annual percentage return realized by the owner of a share of Company Stock for each Year during a relevant Performance Period. The annual percentage return is equal to the appreciation or depreciation in value of a share of Company Stock (which is equal to the average closing value of the stock over the last ten trading days of the relevant period minus the average closing value of the stock over the last ten trading days of the preceding Year) plus the dividends paid on such share during the relevant period, divided by the average closing value of the stock over the last ten trading days of the preceding Year. For purposes of the Total Business Return, the average closing value of the stock shall be a calculated stock price equal to (i) an earnings amount equal to the Company’s ongoing earnings (excluding non-core earnings) for each Year of measurement times (ii) the average price-to-earnings ratio of the Company’s common stock over the last ten trading days of the Year preceding the Year of award.

1.16 “Year” means a calendar year.

Section 2. Sub-Plan Participation and Awards

2.1 Participant Selection. Participants under this Sub-Plan shall be selected by the Committee in its sole discretion as provided in Section 4.2 of the Plan.

2.2 Awards. The Compensation Committee may, in its sole discretion, grant Awards to some or all of the Participants in the form of a specific number of Performance Shares. Except as described below, the target and maximum value of any Award granted to any Participant in any calendar Year will be based upon the following:

Participant	Target Award	Maximum Award
CEO*	233% of Salary	291.25% of Salary
COO*	184% of Salary	230% of Salary
CFO*	133% of Salary	166.25% of Salary
Presidents*/Executive VPs*	117% of Salary	146.25% of Salary
Senior VPs*	100% of Salary	125% of Salary
VP/Department Heads**		
Level I	80% of Salary	100% of Salary
Level I	67% of Salary	83.75% of Salary
Key Managers	67% of Salary	83.75% of Salary

* Senior Management Committee level position
**Levels shall be determined in the sole discretion of the Committee

2.3 Award Valuation at Grant. In calculating the value of an Award for purposes of Section 2.2, the value of each Performance Share shall be equal to the closing price of a share of Stock on the last trading day of the Year before the Performance Period begins. The Participant's Salary shall be determined as of the January 1 preceding the date the Award is granted, or such other time as is determined in the discretion of the Committee. Each Award is deemed to be granted on the day that it is approved by the Committee.

2.4 Accounting and Adjustment of Awards. The number of Performance Shares awarded to a Participant shall be recorded in a separate Account for each Participant. The number of Performance Shares recorded in a Participant's Account shall be adjusted to reflect any splits or other adjustments in the Stock in accordance with Section 6.4 of the Plan. If any cash dividends are paid on the Stock, the number of Performance Shares in each Participant's Account shall be increased by a number equal to (i) the dividend multiplied by the number of Performance Shares in each Participant's Account, divided by (ii) the closing price of a share of Stock on the payment date of the dividend. No adjustment shall be made to any outstanding Awards of a Retired Participant for cash dividends paid on Stock during the Performance Period following the Retirement of the Participant.

2.5 Performance Schedule and Calculation of Awards.

(a) The Committee shall, as soon as practicable after the end of the Performance Period, but in no event later than April 15 of the first Year immediately following expiration of the Performance Period, certify as to (i) the Company's average Total Business Return over the Performance Period, and (ii) the applicable percentage of the Performance Shares vesting in accordance with the Performance Schedule contained in Attachment 1 hereto.

(b) Notwithstanding the Company's average Total Business Return over the Performance Period, the Committee may in its sole discretion, with respect to any or all Participants, elect to vest fewer Performance Shares than indicated by the Performance Schedule. This subsection 2.5(b) shall cease to apply upon the occurrence of a Change in Control.

(c) Except with respect to the adjustments required or permitted by subsection (b) above, the performance measures and the Performance Schedule will not change during any Performance Period with regard to any Awards that have already been granted. The Committee reserves the right to modify or adjust the performance measures and/or the Performance Schedule in the Committee's sole discretion with regard to future grants.

(d) Except in the case of an Early Vesting Event, each Award shall become vested on January 1 immediately following the end of the applicable Performance Period. In no event shall such "normal" vesting date be construed to be earlier than January 1 immediately following the end of the applicable Performance Period.

2.6 Payment of Awards. Except as provided in Section 3, Awards shall be paid after expiration of the Performance Period. The Company will issue one share of Stock, or cash equal to the Fair Market Value of one share of Stock, or a combination thereof as determined by the Committee, in payment for each vested Performance Share (rounded to the nearest whole Performance Share) credited to the Account of the Participant. Payment shall be made as follows:

(a) Normal Payment. Unless deferred as provided below, 100% of the vested Performance Shares for a Performance Period shall paid no later than April 15 of the Year immediately following expiration of the Performance Period. Shares of Stock issued to the Participant will be delivered in certificated or uncertificated form, as the Participant shall direct.

(b) Deferred Payment. Any Participant who is employed as a Department Head or in a higher position as of the beginning of a Performance Period may elect to defer the payment of his or her Performance Shares for that Performance Period by executing a deferral election substantially in the form attached hereto as Attachment 2, and returning it to the Vice President, Human Resources Department no later than the end of the first Year of the Performance Period. Once made, this election shall be irrevocable except as may be permitted by rules promulgated under Section 409A and allowed by the Committee.

2.7 Grantor Trust. In the case of a Change in Control, the Company shall, subject to the restrictions in this Section 2.7 and Section 13.12 of the Plan, irrevocably set aside shares of Stock or cash in one or more such grantor trusts in an amount that is sufficient to pay each Participant employed by such Company (or Designated Beneficiary), the net present value as of the date on which the Change in Control occurs, of the earned benefits to which Participants (or their Designated Beneficiaries) would be entitled pursuant to the terms of the Plan if the value of their deferral account (if any) established pursuant to section 2.6(b) would be paid in a lump sum upon the Change in Control. Any such trust shall be subject to the claims of the general creditors of the Sponsor or Company in the event of bankruptcy or insolvency of the Sponsor or Company. Notwithstanding the foregoing provisions of this Section 2.7, the Company shall establish no such trust if the assets thereof shall be includable in the income of Participants thereby pursuant to Section 409A(b).

Section 3. Early Vesting and Forfeiture

3.1 Retirement, Death, Disability or Divestiture. In the event of the Retirement, Death, Disability or Separation from Service of a Participant due to Divestiture prior to the end of a Performance Period, the outstanding Awards of the Participant shall vest as follows:

(a) Retirement. If the Participant Retires on account of Normal Retirement during a Performance Period, any outstanding Awards of the Participant for such Performance Period shall vest as of the date of such Normal Retirement. If the Participant Retirees on account of Early Retirement during a Performance Period, a portion of the outstanding Awards of the Participant for such Performance Period shall vest as of the date of such Early Retirement. Such vested portion shall be determined by multiplying the number of unvested Performance Shares for the Performance Period by a fraction, the numerator of which is the number of full calendar months during the Performance Period completed by the Participant prior to such Early Retirement, and the denominator of which is 36.

(b) Death. If the Participant dies with fewer than six months remaining during a Performance Period, any outstanding Awards of the Participant for such Performance Period shall vest as of the date of death. If the Participant dies with six or more months remaining during a Performance Period, a portion of the outstanding Awards of the Participant for such Performance Period shall vest as of the date of death. Such vested portion shall be determined by multiplying the number of unvested Performance Shares for the Performance Period by a fraction, the numerator of which is the number of full calendar months during the Performance Period completed by the Participant prior to the date of death, and the denominator of which is 36.

(c) Disability. In the event of the Separation from Service of a Participant due to Disability during a Performance Period, a portion of the outstanding Awards of the Participant for such Performance Period shall vest as of the date of Separation from Service. Such vested portion shall be determined by multiplying the number of unvested Performance Shares for the Performance Period by a fraction, the numerator of which is the number of full calendar months during the Performance Period completed by the Participant prior to the Separation from Service, and the denominator of which is 36.

(d) Divestiture. If the Participant Separates from Service due to Divestiture with fewer than six months remaining during a Performance Period, any outstanding Awards of the Participant for such Performance Period shall vest as of the date of Separation from Service. If the Participant Separates from Service due to Divestiture with six or more months remaining during a Performance Period, a portion of the outstanding Awards of the Participant for such Performance Period shall vest as of the date of Separation from Service. Such vested portion shall be determined by multiplying the number of unvested Performance Shares for the Performance Period by a fraction, the numerator of which is the number of full calendar months during the Performance Period completed by the Participant prior to the date of Separation from Service, and the denominator of which is 36.

3.2 Change in Control. In the event of a Change in Control prior to the expiration of the Performance Period, any outstanding Award of the Participant for any unexpired Performance Period shall be treated as follows:

(a) Awards Assumed by Acquiror. If the Award is assumed by the successor to the Sponsor as of the date of the Change in Control, each outstanding Award not previously forfeited shall continue to vest and shall be paid pursuant to the terms of this Sub-Plan; provided, however, that in the event the employment of the Participant is terminated by the Company without Cause following the Change in Control, any outstanding Award shall become vested as of the termination date.

(b) Awards Not Assumed by Acquiror. If the Award is not assumed by the successor to the Sponsor as of the date of the Change in Control, any outstanding Award shall become vested as of the date of the Change in Control.

3.3 Payment of Awards Due to Early Vesting Event. Any Award that is vested prior to the end of the Performance Period due to an Early Vesting Event in accordance with Section 3.1 shall be paid as follows:

(a) Retirement. In the event of the Retirement of the Participant, the Participant's vested Awards shall be paid in accordance with Section 2.6 following the end of the Performance Period for the Award; provided, that if the Participant has elected to defer payment until a specified date certain and Retires before the date specified in the deferral election, the Company will commence distribution of the Deferred Award as soon as practicable on or after the later of: (i) the April 1 following the first anniversary of the date of Retirement, or (ii) the April 1 of the year following the end of the Performance Period, even though said date is earlier than the date specified in the deferral election. If the Participant dies following Retirement but prior to the expiration of the Performance Period, the Participant's outstanding vested Awards shall be paid to the Participant's Designated Beneficiary in accordance with Section 3.3(b).

(b) Death. In the event of the death of the Participant with fewer than six months remaining during a Performance Period, any outstanding Awards shall be paid in accordance with Section 2.6 following the end of the Performance Period. In the event of the death of the Participant with six or more months remaining during a Performance Period, payment for the Participant's vested Awards shall be made to the Participant's Designated Beneficiary in an amount equal to the target value of such Awards within thirty days after the Participant's death, notwithstanding any election to defer the payment of any Award under Section 2.6(b).

(c) Disability. In the event of the Separation from Service of a Participant due to Disability, the Participant's vested Awards shall be paid in accordance with Section 2.6 following the end of the Performance Period.

(d) Divestiture. In the event of the Separation from Service of the Participant due to Divestiture with fewer than six months remaining during a Performance Period, any outstanding Awards shall be paid in accordance with Section 2.6 following the end of the Performance

Period. In the event of the Separation from Service of the Participant due to Divestiture with six or more months remaining during a Performance Period, payment for the Participant's vested Awards shall be made in an amount equal to the target value of such Awards within thirty days after the Separation from Service due to Divestiture, notwithstanding any election to defer the payment of any Award under Section 2.6(b).

(e) Change in Control. If the Award vests pursuant to Section 3.2(b) or by reason of an involuntary termination of employment without Cause following a Change in Control pursuant to Section 3.2(a), the target value of such Award shall be paid within 30 days after such Early Vesting Event, notwithstanding any election to defer the payment of any Award under Section 2.6(b).

(f) 409A Delay. Notwithstanding subsections (a), (d) or (e) above, if the Participant is a "key employee" as defined in Section 416(i) of the Code (but determined without regard to paragraph 5 thereof or the 50 employee limit on the number of officers treated as key employees), then payment shall not be made before the date that is six months after the date of Separation from Service (or, if earlier, the date of death of the Participant) and the amount of any payment made in cash shall be based upon the value of the Performance Shares as determined by reference to the closing price of the Stock on the trading day occurring on or next following the date that is six months after the date of Separation from Service of the Participant (or, if earlier the date of death of the Participant).

3.4 Other Termination of Employment. In the event that a Participant's employment with the Company terminates for any reason other than as provided in this Section 3, any Award made to the Participant that has not vested as provided in Section 2 or Section 3 shall be forfeited.

Section 4. Payment of Taxes

The Company has the authority and the right to deduct or withhold, or require a Participant to remit to the employer, an amount sufficient to satisfy federal, state, and local taxes (including the Participant's FICA obligation) required by law to be withheld with respect to any taxable event arising as a result of the vesting or settlement of the Performance Shares. The obligations of the Sponsor under this Sub-Plan will be conditional on such payment or arrangements, and the Sponsor, and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to the Participant. By participating in this Sub-Plan, each Participant thereby authorizes the Company to instruct a third party broker or plan administrator to sell Shares earned by the Participant upon settlement of the Performance Shares in an amount sufficient to satisfy the amount required to be withheld for tax purposes, and to remit the cash proceeds from such sale to the Company.

Section 5. Non-Assignability of Awards

The Awards and any right to receive payment under the Plan and this Sub-Plan may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a Participant becomes bankrupt, then in the sole discretion of the

Committee, any Award made to the Participant which has not vested as provided in Sections 2 and 3 shall be forfeited.

Section 6. Amendment and Termination

This Sub-Plan shall be subject to amendment, suspension, or termination as provided in the Plan. No action to amend, suspend or terminate this Sub-Plan shall permit the acceleration of the time or schedule of the payment of any Award granted under this Sub- Plan (except as provided in regulations under Section 409A).

Section 7. Section 409A

This Sub-Plan shall be administered in compliance with Section 409A.

IN WITNESS WHEREOF, this instrument has been executed this ______ day of __________, 2008.

PROGRESS ENERGY, INC.

By: ______________________________
William D. Johnson
Chief Executive Officer

ATTACHMENT 1

PERFORMANCE SCHEDULE

PERFORMANCE SHARE CALCULATION

for Post-2007 Performance Awards

Total Business Return(1)	<__(2)__%	___(2)__%	___(2)__%	__(2)_% or >
% of Target Award Earned(2)	0%	50%	100%	200%

1 Straight line interpolation between points
2 Total Business Return performance measures and associated payout percentages to be established by the Committee on an annual basis.

Committee Discretion. Unless a Change in Control shall have occurred, the Committee retains the sole discretion to reduce the number of Performance Shares earned, with respect to any or all Participants, if the formula would result in payouts that the Committee deems to be disproportionate to Company performance or other circumstances merit a reduction in the amounts earned.

Payment of Awards. The number of Performance Shares earned shall be paid in accordance with the provisions of Section 2.6 or 3.3 of the Sub-Plan, as appropriate.

ATTACHMENT 2

PERFORMANCE SHARE SUB-PLAN
200_ DEFERRAL ELECTION FORM

As a Participant in the Performance Share Sub-Plan of the 2007 Equity Incentive Plan ("Sub-Plan"), I hereby elect to defer payment of my Award otherwise payable to me by the Company and attributable to services to be performed by me during the Performance Period beginning on January __, 200__. This election shall apply to *[CHECK ONE]* :

[ ] 100% of the Award [ ] 50% of the Award

[ ] 75% of the Award [ ] 25% of the Award

Upon vesting, I understand that my Award shall continue to be recorded in my Account as Performance Shares as described in the Sub-Plan and adjusted to reflect the payment and reinvesting of the Company's common stock dividends over the deferral period, until paid in full.

I hereby elect to defer receipt (or commencement of receipt) of my Award until the date specified below *[CHECK ONE]:**

[ ] a specific date certain at least 5 years from expiration of the Performance Period: 4/1/

(month/day/year)

[ ] the April 1 following the date of Retirement, or if later, the date which is six months after the date of my Separation from Service for any reason (including Retirement), if I am a "key employee" as defined in Section 416(i) of the Code (but determined without regard to paragraph 5 thereof or the 50 employee limit on the number of officers treated as key employees).

[ ] the April 1 following the first anniversary of my date of Retirement

* Notwithstanding any election above, if I elect a date certain distribution and I Retire before that date certain, I understand that the Company will commence distribution of my Account as of the later of: (i) the April 1 following the first anniversary of the date of Retirement, or (ii) the April 1 of the year following the end of the Performance Period, even though said date is earlier than 5 years from the expiration of the Performance Period.

I hereby elect to be paid as described in the Sub-Plan in the form of *[CHECK ONE]:*

[ ] a single payment

[ ] annual payments commencing on the date set forth above and payable on the anniversary date thereof over:

[ ] a two year period [ ] a three year period

[ ] a four year period [ ] a five year period

I understand that I will receive “earnings” on those deferred amounts when they are paid to me.

I understand that the election made as indicated herein is irrevocable and that all deferral elections are subject to the provisions of the Sub-Plan, including provisions that may affect timing of distributions.

I understand that this deferral election is subject to the requirements of Section 409A of Code, and regulations and other guidance issued thereunder. The Company makes no representation or guarantee that any tax treatment, including, but not limited to, federal, state and local income, or estate and gift tax treatment, will be applicable with respect to the amounts deferred. The Company shall have no responsibility for the tax consequences that I may incur as a result of Section 409A, regulations or guidance issued thereunder, or any other provision of the Internal Revenue Code. I understand it is my responsibility to consult a legal or tax advisor regarding the tax effects of this deferral election. I further acknowledge and agree that the Company may (but shall not be required to) modify this election as necessary to comply with Section 409A and any guidance or regulations issued thereunder. I further agree to cooperate in any manner necessary to ensure that this election is in compliance with Section 409A and any guidance or regulations issued thereunder.

I understand and acknowledge that my interests herein and my rights to receive distribution of the deferred amounts may not be anticipated, alienated, sold, transferred, assigned, pledged, encumbered, or subjected to any charge or legal process, and if any attempt is made to do so, or I become bankrupt, my interest may be terminated by the Committee, in its sole discretion, may cause the same to be held or applied for the benefit of one or more of my dependents or make any other disposition of such interests that it deems appropriate. I further understand that nothing in the Sub-Plan shall be interpreted or construed to require the Company in any manner to fund any obligation to me, or to my beneficiary(ies) in the event of my death.

(Signature)	(Date)
(Print Name)	(Company Location)

Received:
Agent of Chief Executive Officer

(Signature)	(Date)

Exhibit 10(b)

PROGRESS ENERGY, INC.

RESTRICTED STOCK UNIT AWARD AGREEMENT

Non-transferable

GRANT TO

Name of the Employee
("Grantee")

by Progress Energy, Inc. (the "Sponsor") of # of Units

Restricted Stock Units (the "Units") representing the right to earn, on a one-for-one basis, shares of the Sponsor's common stock ("Stock"), pursuant to and subject to the provisions of the Progress Energy, Inc. Amended and Restated 2007 Equity Incentive Plan (the "Plan") and to the terms and conditions set forth on the following pages of this award agreement ("Agreement"). Capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Plan.

By accepting this award, Grantee shall be deemed to have agreed to the terms and conditions of this Agreement and the Plan. Unless vesting is accelerated as provided in section 2 of the Terms and Conditions or otherwise in the discretion of the Sponsor's Committee on Organization and Compensation ("Committee"), the Units shall vest (become non-forfeitable) in 1/3 increments on each of the 1st, 2nd, and 3rd anniversaries of the Grant Date.

IN WITNESS WHEREOF, Progress Energy, Inc. has caused this Agreement to be executed as of the Grant Date, as indicated below.

PROGRESS ENERGY, INC.

By: ____

Grant Date: ____________________

TERMS AND CONDITIONS

1. Grant of Units. Each Unit represents the right to receive one share of the Sponsor's Stock on the terms set forth in this Agreement.

2. Vesting of Units. The Units have been credited to a bookkeeping account on behalf of Grantee. The Units will vest and become non-forfeitable on the earliest to occur of the following (the "Vesting Date"):

(a) As to one-third of the units on the first anniversary of the Grant Date, another one-third on the second anniversary of the Grant Date, and the remaining one-third on the third anniversary of the Grant Date;

(b) As to all of the Units, the termination of Grantee's employment with the Company due to death or Disability (as defined for purposes of Code Section 409A) at least one year following the Grant Date;

(c) As to all of the Units, the involuntary termination of Grantee's employment with the Company due to Divestiture;

(d) As to all of the Units, upon the occurrence of a Change in Control (as defined for purposes of Code Section 409A), if the Units are not assumed by the surviving company or equitably converted or substituted;

(e) As to all of the Units, upon termination of Grantee's employment by Sponsor without Cause at any time after a Change in Control; or

(f) As to all of the Units, upon Grantee's Normal Retirement on or after attaining age 65. Upon Grantee's Early Retirement on or after age 55 with 10 or more years of service, a prorata percentage of the then-unvested Units, if any, will vest based upon the number of full months elapsed between the Grant Date and the date of Early Retirement, divided by the number of months within the applicable vesting period described in 2(a) above.

If Grantee's employment terminates prior to the Vesting Date for any reason other than as described in (b), (c) or (e) or (f) above, Grantee shall forfeit all right, title and interest in and to the then unvested Units as of the date of such termination and the unvested Units will be reconveyed to the Sponsor without further consideration or any act or action by Grantee.

3. Conversion to Stock. Unless the Units are forfeited prior to the Vesting Date as provided in Section 2 above, the Units will be converted to Shares on the later of (i) the Vesting Date, or (ii) if required to comply with Code Section 409A and Treasury regulations and guidance with respect to such law, the six-month anniversary of Grantee's separation from service (the "Conversion Date"). Such Shares will be registered on the books of the Sponsor in Grantee's name as of the Conversion Date and delivered to Grantee within 30 days thereafter, in certificated or uncertificated form, as the Participant shall direct.

4. Dividend Equivalents. If and when cash dividends or other cash distributions are paid with respect to the Stock while the Units are outstanding, the dollar amount of such dividends or distributions with respect to the number of Shares then underlying the Units will be paid to Grantee within 30 days after the date that dividends are paid to shareholders of the Sponsor.

5. Rights as Stockholder. Except for the right to receive Dividend Equivalents as provided in Section 4 above, Grantee shall not have any rights as a stockholder of the Sponsor with respect to the Units, including voting rights, until conversion of the Units to shares of Stock. Upon conversion of the Units into shares of Stock, Grantee will obtain full voting and other rights as a stockholder of the Sponsor.

6. Restrictions on Transfer. The Units may not be sold, transferred, exchanged, assigned, pledged, hypothecated or otherwise encumbered to or in favor of any party other than the Company, or be subjected to any lien, obligation or liability of Grantee to any other party other than the Company.

7. No Right of Continued Employment. Nothing in this Agreement shall interfere with or limit in any way the right of the Company to terminate Grantee's employment at any time, nor confer upon Grantee any right to continue in the employ of the Company.

8. Payment of Taxes. The Company has the authority and the right to deduct or withhold, or require Grantee to remit to the employer, an amount sufficient to satisfy federal, state, and local taxes (including Grantee's FICA obligation) required by law to be withheld with respect to any taxable event arising as a result of the vesting or settlement of the Units. The obligations of the Sponsor under this Agreement will be conditional on such payment or arrangements, and the Sponsor, and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such

taxes from any payment of any kind otherwise due to Grantee. Grantee hereby authorizes the Company to instruct a third party broker or plan administrator to sell Shares earned by Grantee upon settlement of the Units in an amount sufficient to satisfy the amount required to be withheld for tax purposes, and to remit the cash proceeds from such sale to the Company.

9. Amendment. The Committee may amend, modify or terminate this Agreement without approval of Grantee; provided, however, that such amendment, modification or termination shall not, without Grantee's consent, reduce or diminish the value of this award determined as if it had been fully vested (i.e., as if all restrictions on the Units hereunder had expired) on the date of such amendment or termination.

10. Plan Controls. The terms contained in the Plan are incorporated into and made a part of this Agreement and this Agreement shall be governed by and construed in accordance with the Plan. In the event of any actual or alleged conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall be controlling and determinative.

11. Successors. This Agreement shall be binding upon any successor of the Sponsor, in accordance with the terms of this Agreement and the Plan.

12. Severability. If any one or more of the provisions contained in this Agreement is invalid, illegal or unenforceable, the other provisions of this Agreement will be construed and enforced as if the invalid, illegal or unenforceable provision had never been included.

13. Notice. Notices and communications under this Agreement must be in writing and either personally delivered or sent by registered or certified United States mail, return receipt requested, postage prepaid. Notices to the Sponsor must be addressed to:

Progress Energy, Inc.
410 South Wilmington Street
Raleigh, NC 27601
Attn: General Counsel

or any other address designated by the Sponsor in a written notice to Grantee. Notices to Grantee will be directed to the address of Grantee then currently on file with the Sponsor, or at any other address given by Grantee in a written notice to the Sponsor.

Exhibit 31(a)

CERTIFICATION

I, William D. Johnson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Progress Energy, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: May 9, 2008

By: /s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Progress Energy, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

   d) disclosed in this quarterly report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s first fiscal quarter in the case of this quarterly report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

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

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

Date: May 9, 2008

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer

Exhibit 31(c)

CERTIFICATION

I, Lloyd M. Yates, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Carolina Power & Light Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

   d) disclosed in this quarterly report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s first fiscal quarter in the case of this quarterly report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

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

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

Date: May 9, 2008

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

Exhibit 31(d)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Carolina Power & Light Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

   d) disclosed in this quarterly report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s first fiscal quarter in the case of this quarterly report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

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

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

Date: May 9, 2008

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer

CERTIFICATION

I, Jeffrey J. Lyash, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Florida Power Corporation;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: May 9, 2008

By: /s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer

Exhibit 31(f)

CERTIFICATION

I, Peter M. Scott III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Florida Power Corporation;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date: May 9, 2008

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Progress Energy, Inc. (the “Company”) for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, William D. Johnson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(b)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Progress Energy, Inc. (the "Company") for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and
Chief Financial Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(c)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Carolina Power & Light Company (the "Company") for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Lloyd M. Yates, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(d)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Carolina Power & Light Company (the "Company") for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and
Chief Financial Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

Exhibit 32(e)

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Florida Power Corporation (the "Company") for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jeffrey J. Lyash, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.

CERTIFICATION FURNISHED PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Florida Power Corporation (the "Company") for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter M. Scott III, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and
Chief Financial Officer
May 9, 2008

This certification is being furnished and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or incorporated by reference in any filing under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended.