Joint Applicants' Response To The Commission Staff's Initial Data Requests Volumes 9G - 9H

PROGRESS ENERGY INC (PGN)

10-K
Annual report pursuant to section 13 and 15(d)
Filed on 03/02/2009
Filed Period 12/31/2008

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, 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, state of incorporation, address of principal executive offices, and telephone number	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

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	(X)	No	( )

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	(X)
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, 2008, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $10,917,873,785. As of June 30, 2008, 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, 2008, 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 23, 2009, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	278,433,758
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 2009 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
Ambac	Ambac Assurance Corporation
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
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 primarily includes the Parent, Progress Energy Service Company and miscellaneous other nonregulated businesses
CR1 and CR2	PEF's Crystal River Units No. 1 and 2 coal-fired steam turbines
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 were wholly owned
ECCR	Energy Conservation Cost Recovery Clause

ECRC	Environmental Cost Recovery Clause
EIP	Equity Incentive Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement and construction
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
FGT	Florida Gas Transmission Company, LLC
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
Florida RPS	Florida renewable portfolio standard
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"
FSP SFAS 132R-1	FASB Staff Position No. SFAS 132(R)-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets"
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 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
Harris	PEC's Shearon Harris Nuclear Plant
IRS	Internal Revenue Service
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Levy	Proposed nuclear plant in Levy County, Florida
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
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
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 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
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
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
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
PVI	Progress Energy Ventures, Inc., formerly referred to as Progress Ventures, Inc.
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REC	Renewable energy certificates
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	PEC's Robinson Nuclear Plant
Rowan	Rowan County Power, LLC
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

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.
Syncora	Syncora Guarantee Inc., formerly XL Capital Assurance, Inc.
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
VIE	Variable interest entity
Ward	Ward Transformer site located in Raleigh, N.C.
Ward OU1	Operable unit for stream segments downstream from the Ward site
Ward OU2	Operable unit for further investigation at the Ward facility and certain adjacent areas

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 2011 and future financing plans; and d) "Other Matters" about our synthetic fuels tax credits, the effects of new environmental regulations, meeting anticipated demand in our regulated service territories, potential nuclear construction 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 ability to meet 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 and potential construction 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 expense (O&M) and large construction projects, the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the duration and severity of the current financial market distress that began in the third quarter of 2008; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; 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; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; 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 reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. 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. As discussed in "Significant Developments" below, most of our nonregulated business operations have been divested. See Note 19 for information regarding the revenues, income and assets attributable to our business segments.

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 have historically had 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.

For the year ended December 31, 2008, our consolidated revenues were $9.167 billion and our consolidated assets at year-end were $29.873 billion.

SIGNIFICANT DEVELOPMENTS

As discussed more fully in Note 3 and under MD&A – "Discontinued Operations," in recent years we divested, or announced divestitures, of multiple nonregulated businesses 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 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) and we sold the remaining operations of Progress Fuels subsidiaries engaged in the coal mining business (Coal Mining).

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; Nuclear Project 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 $4.4 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. 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.

WHOLESALE COMPETITION

The Utilities compete with other utilities and merchant generators 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 attract new wholesale customers and 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. PEC and PEF made compliance filings on March 17, 2008, in order to meet the requirements of Order 890-A and are awaiting FERC approval.

The Utilities are operating under revised OATT rates, which were effective for PEC on July 1, 2008, and for PEF on January 1, 2008. The Utilities moved 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. The new rates increased PEC's 2008 revenues by $7 million and increased PEF's 2008 revenues by $2 million. The new rates will have a greater impact on PEF in 2011 when all of PEF's wholesale customers become subject to the new rates.

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 Order No. 890 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 is anticipated to include 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. FERC has approved both PEC and PEF's regional grid planning processes subject to modification. PEF and PEC filed compliance filings with FERC on October 7, 2008, and December 17, 2008, respectively, and are awaiting approval.

The FERC requires that entities desiring to make wholesale sales of electricity at market-based rates document that they do not possess market power. Market power is exercised when an entity profitably drives up prices through its control of a single activity, such as electricity generation, where it controls a significant share of the total capacity available to the market. The FERC has established screening measures for such determinations. Given the difficulty PEC believed it would experience in passing one of the screens, PEC revised its market-based rate tariffs in 2005 to restrict PEC to sales outside of its control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. Accordingly, PEC and PEF make wholesale sales of electricity at cost-based rates in areas inside of PEC's control area and peninsular Florida and 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 regional transmission organizations (RTOs) and advocated the view that regulated, unbundled transmission would facilitate competition in both wholesale and retail electricity markets. The Utilities have previously participated in RTO efforts, but are not active in these efforts currently due to the FERC's termination of both the GridSouth Transco, LLC (GridSouth) and the GridFlorida RTO proceedings. GridSouth was terminated by the GridSouth participants due to not reaching a consensus on creating a southeastern RTO. GridFlorida was terminated by the FPSC and the FERC due to the conclusion that it was not beneficial to jurisdictional customers. PEC's recorded investment in GridSouth totaled $19 million at December 31, 2008. Excluding the immaterial South Carolina retail portion, the GridSouth costs will be fully amortized and recovered by 2012. 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 240 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, 19 expire during the period 2010 through 2013, and the remaining agreements expire between 2014 and 2068. PEC has no franchise agreements that expire in 2009. PEC also provides service within a number of municipalities and in all of the unincorporated areas within its service area without franchise agreements.

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 within its service area without franchise agreements. The general effect of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. 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, 36 expire between 2009 and 2013, and the remaining agreements expire between 2014 and 2037.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

The Parent is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to 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

EPACT also contained provisions for 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 United States 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. 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. During 2008, a number of approved standards were further clarified through the interpretation and revision process. There are currently 94 mandatory NERC standards.

Based on the 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.

The FRCC, SERC and NERC have proposed that entities that self-reported noncompliance prior to the mandatory compliance effective date, pursued aggressive mitigation plans, and completed them, will not be assessed fines. Prior to the June 18, 2007 effective date of mandatory compliance with the reliability standards, PEC self-reported two noncompliances to the SERC and PEF self-reported three noncompliances to the FRCC. PEC completed the mitigation plans for violations reported prior to the effective date. PEF completed two of the mitigation plans for violations reported prior to the effective date. PEF has met the milestones of its third mitigation plan and is on track to complete it during the second quarter of 2009.

Subsequent to the effective date, PEC self-reported to the SERC three noncompliances with voluntary standards. PEC submitted and completed mitigation plans for these noncompliances with voluntary standards. PEC does not expect enforcement actions on noncompliances to voluntary standards. PEC also self-reported to the SERC a violation of a mandatory standard and filed and completed a mitigation plan. PEC has advised the SERC that it would like to enter settlement discussions related to this violation.

Subsequent to the effective date, PEF self-reported to the FRCC two noncompliances with voluntary standards and four violations of a mandatory standard. PEF has filed, completed and closed the mitigation plan for noncompliances with the voluntary standards. PEF has filed mitigation plans for the four mandatory violations and completed three of the mitigation plans. The fourth mitigation plan is on schedule and is expected to be completed during 2010. PEF advised the FRCC that it would like to enter settlement discussions related to these four violations. Neither the violations 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 United States 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 North Carolina Utilities Commission (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 net 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 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 thresholds in 2008 and thus 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 and were $1.664 billion and $1.716 billion, respectively, for 2008. For 2009, the threshold for revenue sharing will be $1.688 billion and the cap will be $1.742 billion.

On February 12, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2010. In its notice, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and that it intends to seek annual rate relief between $475 million to $550 million. PEF intends to file its case-in-chief on March 20, 2009. The request for increased base rates is based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems. If approved by the FPSC, the new base rates would increase residential bills by approximately $15.00 per 1,000 kWh, or 11 percent, effective January 1, 2010. We cannot predict the outcome of this matter.

As part of its February 12, 2009 notification, PEF also informed the FPSC that it may seek additional rate relief in 2009, primarily driven by the addition of its repowered Bartow power plant, which is expected to begin commercial operation in June 2009; and decreased sales and higher pension costs impacted by the current financial and credit crises. We cannot predict the outcome of this matter.

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 generally 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 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), energy-efficiency programs and costs of reagents (commodities such as ammonia and limestone used in emissions control technologies) and eligible renewable energy costs;
- *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 and NOx emission allowance expenses.

As discussed more fully in MD&A – "Other Matters – Regulatory Environment," eligible nuclear costs not previously recoverable through cost-recovery clauses are recoverable in the Florida retail jurisdiction beginning in 2009.

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.

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. Intervenors reserve the right to challenge the interim surcharge recovery of the additional 20 percent above the 80 percent of the claimed deficiency of the storm reserve. 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 and new plant construction, the technological and financial aspects of decommissioning plants at the end of their licensed lives and requirements relating to nuclear insurance. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

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). All of PEC's nuclear plants have received renewed operating licenses as Harris received a 20-year extension from the NRC on its operating license on December 17, 2008. NRC operating licenses for Brunswick No. 1 and No. 2, Harris and Robinson currently expire in September 2036, December 2034, October 2046 and July 2030, respectively.

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. On December 18, 2008, PEF submitted an application to the NRC requesting a 20-year extension of the CR3 operating license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

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. NRC approval is required for the first and third stage design modification. 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).

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

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed combined license (COL) applications to potentially construct new nuclear plants in North Carolina and Florida (See Item 1A "Risk Factors"). 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 17, 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. On June 4, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene 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. One petition to intervene was filed with the NRC within the 60-day notice period. We cannot predict the outcome of this matter. 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 2019.

On December 12, 2006, we announced that PEF selected a greenfield site in Levy County, Fla., (Levy) 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. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors. The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. On October 6, 2008, the NRC docketed, or accepted for review, the Levy nuclear project 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. On December 8, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene 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. One petition to intervene was filed with the NRC within the 60-day notice period. We cannot predict the outcome of this matter. On December 31, 2008, PEF signed an agreement with Westinghouse Electric Company LLC and Stone & Webster, Inc. for the engineering, procurement and construction of two nuclear units at Levy. The contract price for the two Levy units combined is approximately $7.650 billion, part of which is subject to agreed upon escalation factors. The total cost for the two generating units is estimated to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion is estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The final cost of the project will depend on the completion dates, which will be determined in large part by the NRC review schedule. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. PEF is assessing the impact of the NRC schedule on the plans and estimated costs for Levy. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, safety-related construction activities could begin as early as 2012, and a new plant could be operational in the 2016 to 2018 timeframe.

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 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 Policy Act of 1982 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 pools through the expiration of its extended operating license.

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 4D 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 hazardous waste sites, including the Ward Transformer site (Ward) and several 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 submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. 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, including specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

As of February 16, 2009, 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. Progress Energy and the International Brotherhood of Electrical Workers entered a new three-year labor contract beginning December 2008. 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 16, 2009, PEC and PEF employed approximately 6,000 and 4,000 full-time employees, respectively.

PEC

GENERAL

PEC is a regulated public utility founded in North Carolina in 1908 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2008, PEC had a total summer generating capacity (including jointly owned capacity) of 12,415 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's 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, 2008, PEC was providing electric services, retail and wholesale, to approximately 1.5 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. 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 $531 million, $498 million and $454 million for the years ended December 31, 2008, 2007 and 2006, respectively. PEC's total assets were $13.165 billion and $11.955 billion as of December 31, 2008 and 2007, 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

	2008	2007	2006
Residential	**38%**	37%	37%
Commercial	**26%**	26%	25%
Wholesale	**17%**	18%	18%
Industrial	**17%**	17%	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

	2008	2007	2006
Coal	**45%**	48%	47%
Nuclear	**43%**	42%	43%
Purchased power	**7%**	5%	6%
Oil/Gas	**4%**	4%	3%
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)	2008	2007	2006
Coal	**$ 3.39**	$ 2.96	$ 2.90
Nuclear	**0.46**	0.44	0.43
Oil	**16.05**	12.28	11.04
Gas	**10.66**	9.19	9.87
Weighted-average	**2.44**	2.21	2.06

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 2009. Almost all of the coal will be supplied from Appalachian coal sources in the United States and will be primarily delivered by rail.

For 2009, PEC has short-term, intermediate and long-term agreements from various sources for approximately 100 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 fifteen years. For a discussion of PEC's plans with respect to spent fuel storage, see "Nuclear Matters."

Purchased Power

PEC purchased approximately 4.8 million MWh, 3.9 million MWh and 4.2 million MWh of its system energy requirements during 2008, 2007 and 2006, respectively, under purchase obligations and operating leases and had 1,310 MW of firm purchased capacity under contract during 2008. PEC may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEC believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

Oil and Gas

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from various suppliers. PEC has dual-fuel generating facilities 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 gas generation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity under other contracts and utilizes 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 summer generating capacity for all four units is 228 MW. PEC submitted an application to relicense for 50 years its Tillery and Blewett Plants and anticipates a decision by the FERC in 2009. The Walters Plant license will expire in 2034.

PEF

GENERAL

PEF is a regulated public utility founded in Florida in 1899 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. At December 31, 2008, PEF had a total summer generating capacity (including jointly owned capacity) of 9,360 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 10,276 MWh was set on February 6, 2009.

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, 2008, 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, Florida Municipal Power Agency, and the city of 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 $383 million, $315 million and $326 million for the years ended December 31, 2008, 2007 and 2006, respectively. PEF's total assets were $12.471 billion and $10.063 billion as of December 31, 2008 and 2007, 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

	2008	2007	2006
Residential	**50%**	52%	53%
Commercial	**25%**	25%	26%
Wholesale	**12%**	9%	7%
Industrial	**7%**	7%	8%
Other retail	**6%**	7%	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

	2008	2007	2006
Oil/Gas	**34%**	32%	31%
Coal	**30%**	31%	32%
Purchased Power	**21%**	23%	22%
Nuclear	**15%**	14%	15%

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)	2008	2007	2006
Oil	**$ 9.24**	$8.54	$7.03
Gas	**10.03**	8.51	7.41
Coal	**3.74**	3.28	3.16
Nuclear	**0.49**	0.48	0.50
Weighted-average	**5.67**	4.85	4.21

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.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from various 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 transportation to serve its peaking load requirements.

Coal

PEF anticipates a requirement of approximately 6 million tons of coal in 2009. 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 the Illinois Basin, Colorado, and South America. Approximately 50 percent of the coal is expected to be delivered by rail and the remainder by water.

For 2009, PEF has intermediate and long-term contracts with various sources for approximately 100 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.

Purchased Power

PEF purchased approximately 10.2 million MWh, 11.1 million MWh and 10.4 million MWh of its system energy requirements during 2008, 2007 and 2006 respectively, under purchase obligations, operating leases and capital leases and had 2,417 MW of firm purchased capacity under contract during 2008. These agreements include approximately 786 MW of capacity under contract with certain QFs. PEF may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEF believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

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 for the foreseeable future. PEF's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEF's plans with respect to spent fuel storage, see "Nuclear Matters."

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 result from PESC 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 $141 million, $120 million and $229 million for the years ended December 31, 2008, 2007 and 2006, respectively. Corporate and Other segment total assets were $17.483 billion and $16.356 billion as of December 31, 2008 and 2007, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS– PROGRESS ENERGY

	Years Ended December 31				
	2008	2007	2006	2005	2004
Energy supply (millions of kWh)					
Generated					
Steam	**46,771**	51,163	48,770	52,306	50,782
Nuclear	**30,565**	30,336	30,602	30,120	30,445
Combustion Turbines/Combined Cycle	**15,557**	13,319	11,857	11,349	9,695
Hydro	**429**	415	594	749	802
Purchased	**14,956**	14,994	14,664	14,566	13,466
Total energy supply (Company share)	**108,278**	110,227	106,487	109,090	105,190
Jointly owned share (a)	**5,780**	5,351	5,224	5,388	5,395
Total system energy supply	**114,058**	115,578	111,711	114,478	110,585
Average fuel cost (per million Btu)					
Fossil	$ **5.35**	$ 4.54	$ 4.17	$ 4.05	$ 3.17
Nuclear fuel	$ **0.46**	$ 0.45	$ 0.44	$ 0.44	$ 0.44
All fuels	$ **3.66**	$ 3.17	$ 2.86	$ 2.83	$ 2.21
Energy sales (millions of kWh)					
Retail					
Residential	**36,328**	37,112	36,280	36,558	35,350
Commercial	**26,080**	26,215	25,333	25,258	24,753
Industrial	**15,174**	15,721	16,553	16,856	17,105
Other Retail	**4,768**	4,805	4,695	4,608	4,475
Wholesale	**21,087**	21,239	19,117	21,137	18,323
Unbilled	**(131)**	33	(371)	(440)	449
Total energy sales	**103,306**	105,125	101,607	103,977	100,455
Company uses and losses	**4,972**	5,102	4,880	5,113	4,735
Total energy requirements	**108,278**	110,227	106,487	109,090	105,190
Electric revenues (in millions)					
Retail	$ **7,585**	$ 7,672	$ 7,429	$ 6,607	$ 6,066
Wholesale	**1,284**	1,188	1,039	1,103	843
Unbilled	**11**	4	(6)	(2)	17
Miscellaneous revenue	**279**	269	262	237	227
Total electric revenues	$ **9,159**	$ 9,133	$ 8,724	$ 7,945	$ 7,153

(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				
	2008	2007	2006	2005	2004
Energy supply (millions of kWh)					
Generated					
Steam	**28,363**	30,770	28,985	29,780	28,632
Nuclear	**24,140**	24,212	24,220	24,291	23,742
Combustion Turbines/Combined Cycle	**2,795**	2,960	2,106	2,475	1,926
Hydro	**429**	415	594	749	802
Purchased	**4,735**	3,901	4,229	4,656	4,023
Total energy supply (Company share)	**60,462**	62,258	60,134	61,951	59,125
Jointly owned share (a)	**5,205**	4,800	4,649	4,857	4,794
Total system energy supply	**65,667**	67,058	64,783	66,808	63,919
Average fuel cost (per million Btu)					
Fossil	**$ 4.01**	$ 3.50	$ 3.37	$ 3.30	$ 2.52
Nuclear fuel	**$ 0.46**	$ 0.44	$ 0.43	$ 0.42	$ 0.42
All fuels	**$ 2.44**	$ 2.21	$ 2.06	$ 2.03	$ 1.57
Energy sales (millions of kWh)					
Retail					
Residential	**17,000**	17,200	16,259	16,664	16,003
Commercial	**13,941**	14,032	13,358	13,313	13,019
Industrial	**11,388**	11,901	12,393	12,716	13,036
Other Retail	**1,466**	1,438	1,419	1,410	1,431
Wholesale	**14,329**	15,309	14,584	15,673	13,222
Unbilled	**(8)**	(55)	(137)	(235)	91
Total energy sales	**58,116**	59,825	57,876	59,541	56,802
Company uses and losses	**2,346**	2,433	2,258	2,410	2,323
Total energy requirements	**60,462**	62,258	60,134	61,951	59,125
Electric revenues (in millions)					
Retail	**$ 3,582**	$ 3,534	$ 3,268	$ 3,133	$ 2,953
Wholesale	**737**	754	720	759	575
Unbilled	**8**	–	(1)	4	10
Miscellaneous revenue	**101**	96	98	94	90
Total electric revenues	**$ 4,428**	$ 4,384	$ 4,085	$ 3,990	$ 3,628

(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				
	2008	2007	2006	2005	2004
Energy supply (millions of kWh)					
Generated					
Steam	**18,408**	20,393	19,785	22,526	22,150
Nuclear	**6,425**	6,124	6,382	5,829	6,703
Combustion Turbines/Combined Cycle	**12,762**	10,359	9,751	8,874	7,769
Purchased	**10,221**	11,093	10,435	9,910	9,443
Total energy supply (Company share)	**47,816**	47,969	46,353	47,139	46,065
Jointly owned share(a)	575	551	575	531	601
Total system energy supply	**48,391**	48,520	46,928	47,670	46,666
Average fuel cost (per million Btu)					
Fossil	**$ 6.87**	$ 5.80	$ 5.09	$ 4.88	$ 3.86
Nuclear fuel	**$ 0.49**	$ 0.48	$ 0.50	$ 0.51	$ 0.49
All fuels	**$ 5.67**	$ 4.85	$ 4.21	$ 4.15	$ 3.21
Energy sales (millions of kWh)					
Retail					
Residential	**19,328**	19,912	20,021	19,894	19,347
Commercial	**12,139**	12,183	11,975	11,945	11,734
Industrial	**3,786**	3,820	4,160	4,140	4,069
Other Retail	**3,302**	3,367	3,276	3,198	3,044
Wholesale	**6,758**	5,930	4,533	5,464	5,101
Unbilled	**(123)**	88	(234)	(205)	358
Total energy sales	**45,190**	45,300	43,731	44,436	43,653
Company uses and losses	**2,626**	2,669	2,622	2,703	2,412
Total energy requirements	**47,816**	47,969	46,353	47,139	46,065
Electric revenues (in millions)					
Retail	**$ 4,003**	$ 4,138	$ 4,161	$ 3,474	$ 3,113
Wholesale	**547**	434	319	344	268
Unbilled	**3**	4	(5)	(6)	7
Miscellaneous revenue	**178**	173	164	143	137
Total electric revenues	**$ 4,731**	$ 4,749	$ 4,639	$ 3,955	$ 3,525

(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. We cannot predict the impact that may result from changes in federal administrative policy under the Obama administration. Additionally, we are subject to legislative changes at the state and federal level. We may become subject to new laws and regulations, including but not limited to, in the areas of environmental compliance, renewable energy standards, and energy policy. Such changes in regulations or the imposition of additional regulations could have an adverse impact on our financial condition and 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 coal combustion product management (disposal or beneficial use) capabilities; 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.

The Utilities purchase fuel, including coal, natural gas, uranium and fuel oil, from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather, environmental regulations, and *force majeure* events, which could limit the Utilities' ability to operate their facilities.

We are subject to compliance with mandatory FERC-approved reliability standards. 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.

Our coal plants produce coal combustion products. The majority of our plants are nearing full capacity for on-site management of coal combustion products. As a result, we are developing new coal combustion product management plans for our coal plants, which will result in additional capital expenditures for construction of on-site management facilities and/or increased O&M costs for off-site management. The federal government has announced its intention to assess coal ash combustion product management sites and will consider federal regulation. 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.

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 exercise 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, including certain prudent compliance and new baseload generation construction 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, including but not limited to, environmental compliance, new generation and transmission facilities, compliance with renewable energy standards, 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 current base rates are subject to traditional cost-based rate regulation. PEF currently operates under a base rate settlement agreement, 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 demand for electricity in our service territories and management of our costs.

Meeting the anticipated demand 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 demand 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.

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 DSM, 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 programs provide 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 mandated renewable energy standards, 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.

Future increases in demand for skilled construction labor may result 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. Demand for the components required for the manufacturing and construction of power plants 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. Like other parts of the country, our service territories and business have been impacted by the current economic recession with corresponding downturns in the housing and consumer credit markets. PEC has experienced some decline in the rate of residential and commercial sales growth and PEF's retail customer base contracted in the latter half of 2008. The timing and extent of the recovery of the economy cannot be predicted. Additionally, our customers may undertake further individual energy conservation measures, which could decrease the demand for electricity. We may increase our baseload capacity and have excess capacity if anticipated growth levels are not realized. The resulting 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. As with any major construction undertaking, completion of our proposed nuclear plants could be delayed or prevented, or cost overruns could be incurred, as a result of numerous factors, including shortages of material and labor, labor disputes, weather interferences, difficulties in obtaining necessary licenses or permits, or in meeting license or permit conditions or unforeseen engineering, environmental or geological problems.

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. PEC has filed a COL application with the NRC for two additional reactors at Harris and PEF has filed a COL application with the NRC for two reactors at Levy. 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 2019. For PEF, if we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, safety-related construction activities could begin as early as 2012, and a new plant could be operational in the 2016 to 2018 timeframe. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

PEF has entered into an engineering, procurement and construction (EPC) agreement for Levy. More than half of the contract price is fixed or firm with agreed upon escalation factors and the remainder of the contract price may fluctuate. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. Some specific costs are priced at actual cost, which may be market driven. (See MD&A – Other Matters – Nuclear – Potential New Construction)

If as a result of unexpected or uncontrollable events specified in the EPC agreement or specified acts or omissions by us, completion of Levy is delayed or prevented, or Levy cannot achieve operation in accordance with design specifications and performance guarantees, the EPC contractor will not be obligated to pay liquidated damages. Generally, the EPC contractor will not be obligated to pay liquidated damages for events or circumstances that adversely affect its ability to perform its obligations under the construction agreement to the extent that the events or circumstances are beyond its reasonable control and are not caused by its or its subcontractors' negligence or lack of due diligence and could not have been avoided by the use of its reasonable efforts. In addition, the date for achievement of provisional acceptance and the guaranteed provisional acceptance under the EPC agreement could be subject to adjustment as a result of unexpected or uncontrollable events. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance.

Under the EPC agreement, we are responsible for a number of matters in connection with the construction, completion and start-up of Levy. Our responsibilities include, but are not limited to, obtainment of the COL; performance, oversight and review of certain surveillance and testing functions; and acceptance of turnover of systems from the contractor. While we believe that we have made adequate arrangements to assure timely performance of our responsibilities, we are relying on other parties to enable us to perform our responsibilities under the EPC agreement and we cannot be certain that the other parties will meet their obligations under their contracts.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant constructed by us would qualify for these 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), NO_x, SO_2 and mercury; an efficient licensing process; and management of coal combustion products such as slag, bottom ash 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 standards that may have a negative impact on our business, financial condition and results of operations.

We are subject to renewable energy standards at the state level in North Carolina and Florida. We may be subject to federal level standards in the future.

North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) law establishes minimum standards 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 NC 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 NC REPS law, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the NC REPS requirements if the NCUC determines it is in the public interest to do so.

Florida's comprehensive energy 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; (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; and (5) require the FPSC to analyze utility revenue decoupling and provide a report and recommendation to the governor and legislature by January 1, 2009. The FPSC concluded and recommended to the governor and legislature that no specific revenue decoupling program needs to be, or should be, implemented at this time. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until the rulemaking processes are completed, we cannot predict the costs of complying with the law.

On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard (Florida RPS) rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida RPS rule to the Florida legislature in February 2009. The legislature will review, ratify as is, make revisions, or decide not to have a Florida RPS rule at all. We cannot predict the outcome of this matter.

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.

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 owns and operates four nuclear units and PEF owns and operates one nuclear unit. 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 and permits 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. 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.

Our compliance with environmental regulations, including those to reduce emissions of NOx, SO_2 and mercury from coal-fired power plants, requires significant capital expenditures that impact our financial condition. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. These costs could be higher than currently expected and have an adverse impact on our results of operations and financial condition. 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 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. Future increases in demand for these items from other utility companies operating similar equipment could increase our costs associated with operating the equipment. The operation of emission control equipment may result in development of collateral issues that require further remedial actions, resulting in additional expenditures and operating costs.

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.

Hydroelectric generating plants represent a small portion of PEC's generation capacity. PEF has no hydroelectric generating plants. 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. 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. In the event future storms cause the reserve to be depleted, PEF can 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 FPSC has the right to review PEF's storm costs for prudence. Storm reserve costs attributable to PEF's 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 are impacted by customer growth in our service territories and may fluctuate with the economy and its corresponding impact on our customers as well as the demand and competitive state of the wholesale market.

Our revenues, operating results and financial condition are impacted by customer growth and usage. Customer growth can be impacted by population growth as well as by economic factors, including but not limited to, job growth and housing market trends. The Utilities are impacted by the economic cycles of the customers we serve. 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. If our commercial and industrial customers experience economic downturns, their consumption of electricity may decline and our revenues can be negatively impacted.

Like other parts of the country, our service territories and business have been impacted by the current economic recession with corresponding downturns in the housing and consumer credit markets. PEC has experienced some decline in the rate of residential and commercial sales growth and PEF's retail customer growth has contracted. We have experienced declining sales to commercial and industrial customers due to the economic recession. The timing and extent of the recovery of the economy cannot be predicted. Additionally, our customers may undertake further individual energy conservation measures, which could decrease the demand for electricity.

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.

Fluctuations in 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, including emission allowances, 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.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We continually monitor our derivative positions in relation to market price activity.

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. The demand and prices for labor and materials are subject to volatility and may increase in the future. 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 emission allowance credits fluctuate. While 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 changes in the price of allowances could have a significant adverse financial impact on us and PEC and consequently, on our results of operations and cash flows.

As a holding company with no revenue-generating operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily the Utilities; its commercial paper and bank facilities; and its ability to access the long-term debt and equity capital markets.

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 its 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; the ability of its subsidiaries to pay upstream dividends or to repay funds due the Parent; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. 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. Additionally, the Utilities could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from the Parent. Should the Utilities not be able to pay dividends or repay funds due to the Parent or if the Parent cannot access the commercial paper market, its bank facilities or the long-term debt and equity capital markets, 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 or pursue improvements 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, long-term debt and equity. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy will be adversely affected. In 2008, extreme market turmoil caused the credit markets to tighten. However, we believe that we will continue to have sufficient access to these financial markets based upon our current credit ratings. Further market disruptions or a downgrade of our credit ratings could increase our cost of borrowing and may adversely affect our ability to access the financial markets. If we cannot fund our expected capital expenditures and debt maturities through normal operations or by accessing capital markets, our business plans, financial condition, results of operations or cash flows may be adversely impacted. See discussion of our expected capital expenditures in MD&A – "Liquidity and Capital Resources – Capital Expenditures".

We issue commercial paper to meet short-term liquidity needs. When financial and economic conditions result in tightened short-term credit markets coupled with corresponding volatility in commercial paper durations and interest rates, we 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, issuing long-term debt and/or issuing equity. 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 and in Note 11, we rely heavily on our commercial paper and long-term debt. As described in Note 11, 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.

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 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. Although a number of factors impact our funding requirements, 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. See further discussion of our nuclear decommissioning trust funds and benefit plan assets in Notes 4D, 13 and 16 and in MD&A – "Application of Critical Accounting Policies and Estimates."

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. 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 Internal Revenue Service (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.

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 steam, nuclear, combustion turbines, combined cycle, and hydroelectric resources, with a total summer generating capacity of 12,415 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2008, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)	Summer Net Capability (a) (in MW)	
FOSSIL STEAM							
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	397	
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	742	(b)
Robinson	Hartsville, S.C.	1	1960	Coal	100	174	
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.30 (c)	2,424	(b)
Sutton	Wilmington, N.C.	3	1954-1972	Coal	100	600	
Weatherspoon	Lumberton, N.C.	3	1949-1952	Coal	100	172	
	Total	19				5,201	
COMBINED CYCLE							
Cape Fear	Moncure, N.C.	2	1969	Oil	100	64	
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100	479	
	Total	3				543	
COMBUSTION TURBINES							
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	327	
Blewett	Lilesville, N.C.	4	1971	Oil	100	52	
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	801	
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	808	
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	694	
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	132	
	Total	41				2,975	
NUCLEAR							
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,858	(b)
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900	(b)
Robinson	Hartsville, S.C.	1	1971	Uranium	100	710	
	Total	4				3,468	
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	89	
Walters	Waterville, N.C.	3	1930	Water	100	112	
	Total	15				228	
TOTAL		82				12,415	

(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, 2008, including both the total generating capacity of 12,415 MW and the total firm contracts for purchased power of 1,310 MW, PEC had total capacity resources of approximately 13,725 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, 2008, 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 54.9 million kilovolt-ampere (kVA) in approximately 900 transformers. Distribution line transformers numbered approximately 538,000 with an aggregate capacity of approximately 24 million kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil steam, combustion turbine, combined cycle, and nuclear resources, with a total summer generating capacity of 9,360 MW. Of this total, joint owners own approximately 120 MW. At December 31, 2008, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability (a) (in MW)
FOSSIL STEAM						
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	1,011
Bartow	St. Petersburg, Fla.	3	1958-1963	Gas/Oil	100	426
Crystal River	Crystal River, Fla	4	1966-1984	Coal	100	2,311
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	131
	Total	12				3,879
COMBINED CYCLE						
Hines	Bartow, Fla.	4	1999-2007	Gas/Oil	100	1,912
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	205
	Total	5				2,117
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	48
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	177
~~Bayboro~~	~~St. Petersburg, Fla.~~	~~4~~	~~1973~~	~~Oil~~	~~100~~	~~174~~
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	645
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	113
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	(b)	987 (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	149
University of Florida Co-generation	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,504
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	860 (c)
	Total	1				860
TOTAL		65				9,360

(a) Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.
(b) PEF and Georgia Power Company are joint owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site. Georgia Power Company 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 2008, including both the total generating capacity of 9,360 MW and the total firm contracts for purchased power of 2,417 MW, PEF had total capacity resources of approximately 11,777 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 Company are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City Unit P11. Georgia Power Company 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, 2008, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and approximately 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 53.7 million kVA in approximately 800 transformers. Distribution line transformers numbered approximately 390,000 with an aggregate capacity of approximately 20 million kVA.

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 23, 2009

Name	Age	Recent Business Experience
William D. Johnson	55	**Chairman, President and Chief Executive Officer, Progress Energy and Florida Progress,** October 2007 to present; **Chairman, PEC and PEF,** from November 2007 to present; President and Chief Operating Officer, Progress Energy, from January 2005 to October 2007; Group President, PEC, from January 2004 to October 2007; Executive Vice President, PEF, from November 2000 to November 2007; Executive Vice President, Florida Progress, from November 2000 to December 2003; and Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress, from 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, from January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, from 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, N.C. office of Hunton & Williams LLP where he specialized in the representation of utilities.
Jeffrey A. Corbett	49	**Senior Vice President, Energy Delivery, PEC,** January 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, from June 2006 to January 2008, 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 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	46	**Senior Vice President, Energy Delivery, PEF,** January 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, Distribution, PEF, from August 2007 to January 2008, Vice President, Distribution Engineering & Operations, PEF, from December 2005 to August 2007, Vice President, Distribution Operations & Support, PEF, from April 2004 to December 2005 and Vice President, Coastal Region, PEF, from December 2000 to April 2004. Mr. Lewis has been with PEF in a number of engineering and management positions since 1986, including District Manager, Distribution Operations Manager in Pasco County, General Manager for the South Coastal region and Regional Vice President of both the North and South Coastal regions.
*Jeffrey J. Lyash	47	**President and Chief Executive Officer, PEF,** June 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, PEF, from November 2003 to June 2006. Prior to coming to PEF, Mr. Lyash was Vice President - Transmission in Energy Delivery, PEC, from January 2002 to October 2003. Mr. Lyash joined Progress Energy (formerly CP&L) in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations.
John R. McArthur	53	**Executive Vice President, Progress Energy,** September 2008 to present. In his various roles, Mr. McArthur is responsible for corporate and utility support functions, including Corporate Services, Corporate Communications, Efficiency and Innovative Technology, External Relations, Human Resources and Information Technology and Telecommunications. The compliance, legal and audit functions are also part of his group. He also serves as Corporate Secretary of Progress Energy, a position he has held since January 2004. Mr. McArthur is also Executive Vice President of PEC since September 2008, Executive Vice President of PEF since November 2008 and Senior Vice President and Secretary of Florida Progress Corporation since January 2004. Mr. McArthur has been with Progress Energy in a number of roles since 2001, including General Counsel, Senior Vice President, Corporate Relations and Vice President, Public Affairs. Before joining Progress Energy, Mr. McArthur was a member of former 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.

Mark F Mulhern	49	**Senior Vice President and Chief Financial Officer, Progress Energy, PEC and PEF,** September 2008 to present. He previously served as Senior Vice President, Finance, PEC and PEF, from November 2007 to September 2008, and Senior Vice President, Finance, Progress Energy, from July 2007 to September 2008. Mr. Mulhern also served as President of Progress Ventures (the unregulated subsidiary of Progress Energy), from 2005 to 2008; Senior Vice President of Competitive Commercial Operations of Progress Ventures, from 2003 to 2005; Vice President, Strategic Planning of Progress Energy, from 2000 to 2003; Vice President and Treasurer of Progress Energy, from 1997 to 2000; and Vice President and Controller of Progress Energy, from 1996 to 1997. Before joining Progress Energy (formerly CP&L) in 1996, Mr. Mulhern was the Chief Financial Officer at Hydra Co Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at Price Waterhouse, serving a wide variety of manufacturing and service businesses.
James Scarola	52	**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 the Brunswick Nuclear Plant from October 2005 to December 2007. Mr. Scarola joined Progress Energy (formerly CP&L) in 1998, where he served as Vice President at the Harris Nuclear Power Plant until October 2005. Mr. Scarola entered the nuclear power field in 1978 as a design engineer and has held positions in construction, start-up testing, maintenance, engineering and operations. He was the Plant General Manager at the St. Lucie Nuclear Plant with Florida Power & Light Company prior to joining Progress Energy.
Frank A. Schiller	47	**Senior Vice President, Compliance and General Counsel, Progress Energy,** January 2009 to present. Mr. Schiller is responsible for Progress Energy's legal, regulatory, compliance, audit and corporate governance functions. He serves as Progress Energy's chief compliance officer and chairs Progress Energy's Ethics Committee. Mr. Schiller joined Progress Energy in 1997 and previously served as Vice President, Legal, from December 2000 to December 2008; Director – Legal Services, from January 2000 to December 2000; and Associate General Counsel, from December 1997 to January 2000 Before joining Progress Energy, Mr. Schiller was Senior Counsel at Virginia Electric and Power Company.

Paula J. Sims	47	**Senior Vice President, Power Operations, PEC and PEF,** July 2007 to present. Ms. Sims oversees fossil generation, new generation and transmission construction, environmental compliance, non-nuclear fuel procurement and transportation, purchased power and excess generation sales. She previously served as Sr. Vice President of Regulated Services from January 2006 to July 2007; Vice President, Fossil Fuel Generation of Progress Energy and PEF, from January 2006 to April 2006; Vice President, Regulated Fuels of Progress Energy, from December 2004 to December 2005; Chief Operating Officer of Progress Fuels Corporation, from February 2002 to December 2004; and Vice President, Business Operations & Strategic Planning of Progress Fuels Corporation, from June 2001 to February 2002. Before joining Progress Energy in 1999, Ms. Sims was with General Electric, where she served in a number of management and operations positions for over 15 years.
Jeffrey M. Stone	48	**Chief Accounting Officer and Controller, Progress Energy and Florida Progress,** June 2005 to present; **Chief Accounting Officer, PEC and PEF,** from June 2005 and November 2005, respectively, to present; and **Vice President and Controller, Progress Energy Service Company, LLC,** from 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; and 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	48	**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, from January 2005 to July 2007, where he 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 and as Vice President - Fossil Generation, from November 1998 to November 2003. Before joining Progress Energy (formerly CP&L) in 1998, Mr. Yates was with PECO Energy for over 16 years in several line operations and management positions. 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
2008			
First Quarter	**$49.16**	**$40.54**	**$0.615**
Second Quarter	**43.58**	**41.00**	**0.615**
Third Quarter	**45.52**	**40.11**	**0.615**
Fourth Quarter	**45.60**	**32.60**	**0.620**
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

The December 31 closing price of our Common Stock was $39.85 for 2008 and $48.43 for 2007. As of February 23, 2009, we had 55,919 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 9 and 11B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2009 Annual Meeting of Shareholders.

Issuer purchases of equity securities for fourth quarter of 2008 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1) (2) (3)	(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	637,120	$38.2458	N/A	N/A
November 1 – November 30	516,600	38.6632	N/A	N/A
December 1 – December 31	165,372	38.9632	N/A	N/A
Total	1,319,092	$38.6106	N/A	N/A

(1) At December 31, 2008, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.
(2) 867,920 shares of our common stock were purchased in open-market transactions by the plan administrator to meet share delivery obligations under the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) (See Note 9B).
(3) 451,172 shares of our common stock were purchased in open-market transactions by the plan administrator to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation.

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. During 2008, PEC paid no dividends to the Parent. During 2007 and 2006, PEC has paid 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 9 and 11). 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 2008 and 2007, PEF paid no dividends to Florida Progress. During 2006, PEF paid dividends to Florida Progress totaling the amounts shown in PEF's Statements of Common Equity included in the financial statements in PART II, Item 8. PEF has provisions restricting dividends in certain circumstances (See Notes 9 and 11). 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)	**2008**	2007	2006	2005	2004
OPERATING RESULTS					
Operating revenues	**$ 9,167**	$ 9,153	$ 8,724	$ 7,948	$ 7,168
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**773**	693	551	523	552
Net income	**830**	504	571	697	759
PER SHARE DATA					
Basic earnings					
Income from continuing operations	**$ 2.97**	$ 2.71	$ 2.20	$ 2.12	$ 2.28
Net income	**3.19**	1.97	2.28	2.82	3.13
Diluted earnings					
Income from continuing operations	**2.96**	2.70	2.20	2.12	2.27
Net income	**3.18**	1.96	2.28	2.82	3.12
ASSETS (a)	**$29,873**	$26,338	$25,832	$27,083	$26,100
CAPITALIZATION AND DEBT					
Common stock equity (b)	**$ 8,687**	$ 8,395	$ 8,259	$ 8,011	$ 7,606
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**6**	84	10	36	29
Long-term debt, net (c)	**10,659**	8,737	8,835	10,446	9,521
Current portion of long-term debt	**–**	877	324	513	349
Short-term debt	**1,050**	201	–	175	684
Capital lease obligations	**239**	247	72	18	19
Total capitalization and debt (b)	**$20,734**	$18,634	$17,593	$19,292	$18,301
Dividends declared per common share	**$ 2.465**	$ 2.445	$ 2.425	$ 2.375	$ 2.315

(a) Balances have been restated for the correction of an error resulting in decreases of $27 million at December 31, 2007 and 2006 and $31 million at December 31, 2005 and 2004 (See Note 1B).

(b) Balances have been restated for the correction of an error resulting in decreases of $27 million at December 31, 2007, 2006, 2005 and 2004 (See Note 1B).

(c) Includes long-term debt to affiliated trust of $272 million at December 31, 2008, $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005 and 2004 (See Note 23)

PEC

(in millions)	Years Ended December 31 2008	2007	2006	2005	2004
OPERATING RESULTS					
Operating revenues	**$ 4,429**	$ 4,385	$ 4,086	$ 3,991	$ 3,629
Net income	**534**	501	457	493	461
Net income available to common stockholders	**531**	498	454	490	458
ASSETS (a)	**$13,165**	$11,955	$11,999	$11,471	$10,756
CAPITALIZATION AND DEBT					
Common stock equity (b)	**$ 4,301**	$ 3,752	$ 3,363	$ 3,091	$ 3,045
Preferred stock – not subject to mandatory redemption	**59**	59	59	59	59
Long-term debt, net	**3,509**	3,183	3,470	3,667	2,750
Current portion of long-term debt	**–**	300	200	–	300
Short-term debt (c)	**110**	154	–	84	337
Capital lease obligations	**16**	17	18	18	19
Total capitalization and debt (b)	**$ 7,995**	$ 7,465	$ 7,110	$ 6,919	$ 6,510

(a) Balances have been restated for the correction of an error resulting in decreases of $27 million at December 31, 2007 and 2006 and $31 million at December 31, 2005 and 2004 (See Note 1B).

(b) Balances have been restated for the correction of an error resulting in decreases of $27 million at December 31, 2007, 2006, 2005 and 2004 (See Note 1B).

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

PEF

The information called for by Item 6 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

The following combined Management's Discussion and Analysis 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," 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 are PEC and PEF and their primary operations are the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. 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 reportable 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 substantially all of our nonregulated businesses. Our two electric utilities operate in regulated retail utility markets in the southeastern United States and have access to attractive 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

The Utilities have more than 21,000 megawatts (MW) of generation capacity, and their service territories cover approximately 54,000 square miles in the southeastern United States, which has historically been one of the fastest-growing regions of the country. We are focused on safely and reliably serving our customer base. However, like other parts of the country, our service territories and business have been impacted by the current economic recession with corresponding downturns in the housing and consumer credit markets. Our customer growth has slowed significantly. We had a net increase of approximately 24,000 retail customers over the past year compared to a net increase of 51,000 retail customers in 2007. However, we were able to mitigate our weaker than expected 2008 retail revenues with strategies of securing additional wholesale revenues and ongoing cost management. We anticipate 2009 will be another challenging year given the recent financial market disruptions and worsening economic conditions.

Successfully implementing our balanced solution for a secure energy future

Our balanced solution is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provide a solid basis for slowing and reducing carbon dioxide (CO_2) emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation. First, we are expanding and enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. Second, we are actively engaged in a variety of alternative energy projects and are evaluating the feasibility of producing electricity from these and other sources. North Carolina's minimum renewable energy portfolio standard begins in 2012. On January 12, 2009, the Florida Public Service Commission (FPSC) approved a draft state renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020; the rule requires legislative ratification before implementation. Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating the best new generation options, 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. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms that our state jurisdictions have implemented, or are in the process of implementing. See "Other Matters – Regulatory Environment" and Note 7 for additional information.

We are continuing to pursue new nuclear generation based on expectations of new federal climate policy as well as recognition of the need for new baseload generating capacity and better fuel diversity and energy security. Favorable changes in the regulatory and construction processes have evolved in recent years, including standardized design, detailed design before construction, combined license (COL) to build and operate, streamlined regulatory approval process, annual prudence reviews and cost-recovery mechanisms for preconstruction and financing costs. State regulatory processes are specific to each jurisdiction. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. In 2008, the Utilities each filed a COL application with the Nuclear Regulatory Commission (NRC) for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy). During 2008, PEF filed and received orders from the FPSC on its Levy Determination of Need and cost-recovery petitions. Also, PEF filed its site certification for Levy, which has an 18-month review period. In late 2008, PEF entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. The next significant step in the Levy project is to negotiate joint ownership agreements. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. PEF is assessing the impact of the NRC schedule on the plans and estimated costs for Levy. Current plans would be for the Levy units to be operational in the 2016 to 2018 timeframe. If PEC proceeds with construction at Harris, a new unit would not be online until at least 2019. See "Other Matters – Nuclear Matters" for additional information.

Maintaining constructive regulatory relations while confronting new energy realities

The Utilities successfully resolved key state regulatory issues in 2008, including retail fuel recovery filings in all jurisdictions. PEC successfully sought to terminate its obligation to recognize accelerated amortization of certain environmental compliance costs in North Carolina and accelerated depreciation of nuclear generating assets in South Carolina. Consequently, PEC will not be required to recognize accelerated expenses totaling \$229 million in the North Carolina jurisdiction and \$38 million in the South Carolina jurisdiction but will record depreciation over the useful life of the respective assets. As discussed previously, PEF's petitions for the Levy Needs Determination and for \$420 million of nuclear cost recovery for the Levy and Crystal River Unit No. 3 Nuclear Plant (CR3) projects were granted by the FPSC. See "Other Matters – Regulatory Environment" and Note 7 for further information.

The Utilities have sought, and will continue to seek, recovery of eligible costs in accordance with the energy policies of their respective jurisdictions. In February 2009, PEF began the process for establishing 2010 base rates by filing notification with the FPSC indicating its intent to initiate a base rate proceeding. This procedural step is required because PEF's current base rate agreement will expire at the end of 2009. In addition, on February 18, 2009, PEF filed a request with the FPSC to decrease customers' bills in 2009 due to a revised fuel forecast and a deferral of a portion of previously approved nuclear preconstruction charges. We cannot predict the outcome of these matters (See "Future Liquidity and Capital Resources – Regulatory Matters and Recovery of Costs" and Note 7C.)

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Federal judicial actions during 2008 vacated mercury emissions regulations and remanded clean air regulations to the United States Environmental Protection Agency (EPA) for modification. Subsequent rule issuances and interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. We currently estimate that total future capital expenditures for the Utilities to comply with 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 $580 million at PEC and $350 million 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 CO_2 and other greenhouse gases. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. While state-level study groups are busy in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. 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. See "Other Matters – Environmental Matters" for additional information.

The American Recovery and Reinvestment Act signed into law in February 2009 contains provisions promoting energy efficiency and renewable energy, including $11 billion for Smart Grid-related technologies, $6.3 billion for energy-efficiency and conservation grants and $2 billion in tax credits for the purchase of plug-in electric vehicles. Also, the Obama administration has announced a goal of sparking a new energy revolution by stimulating transmission and promoting renewable resources while also pricing greenhouse gas emissions and setting a federal requirement for renewable energy. We are currently reviewing the impact the new legislation might have on our operations. The impact of the new legislation and regulation resulting from other federal initiatives cannot be determined at this time.

Achieving our long-term financial objectives and sustaining financial strength and flexibility during anticipated nuclear construction

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 21 consecutive years, and 33 of the last 34 years. We will strive to preserve our investment grade credit ratings so that we are positioned to accommodate the significant future demand expected at the Utilities.

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 control, and the timing of recovery of fuel costs and storm damage. The Utilities contributed $914 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2008. Partially offsetting the Utilities' segment profit contribution were losses of $141 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

Ongoing cost management initiatives have enabled us to offset some of the impact of the slowing economy and high cost pressures. 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 attempt to mitigate rising fuel prices through our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity. Mitigating the impact of rising fuel prices benefits our cash flows, interest expense and leverage. Additionally, recovery of higher fuel costs negatively impacts customer satisfaction.

In addition to the significant capital investment required for complying with environmental regulations and meeting anticipated load growth, the Utilities' operations are inherently capital intensive. We have addressed the challenges presented by current financial market conditions and will continue to monitor the credit markets to maintain an appropriate level of liquidity. Despite the tightened credit market that began with the extreme market turmoil in the third quarter of 2008, we have been able to issue additional equity and short- and long-term debt. See "Liquidity and Capital Resources."

We expect total capital expenditures before potential nuclear construction to be approximately $2.2 billion, $2.1 billion and $2.0 billion for 2009, 2010 and 2011, respectively. If we determine to proceed with the construction of a new nuclear facility, we expect that our potential nuclear construction expenditures will range from $260 million to $560 million in 2009, $460 million to $660 million in 2010 and $750 million to $950 million in 2011. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentage of joint ownership. PEF has utilized, and anticipates continuing to utilize, nuclear cost-recovery mechanisms for nuclear preconstruction and construction cost financing available under Florida law. Subject to regulatory approval, capital investments that 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.

Our now discontinued synthetic fuels operations historically produced significant net earnings driven by tax credits for synthetic fuels production in accordance with the Section 29/45K tax credit program (Section 29/45K), which expired at the end of 2007. However, the associated cash flow benefits are realized over time when deferred Section 29/45K tax credits generated, but not yet utilized, are ultimately utilized. At December 31, 2008, the amount of these deferred tax credits carried forward was $799 million. See "Other Matters – Synthetic Fuels Tax Credits" below and Note 22D for additional information on our synthetic fuels tax credits and other matters.

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 2008 AS COMPARED TO 2007 AND 2007 AS COMPARED TO 2006

For the year ended December 31, 2008, our net income was $830 million, or $3.19 per share, compared to $504 million, or $1.97 per share, for the same period in 2007. For the year ended December 31, 2008, our income from continuing operations was $773 million compared to $693 million for the same period in 2007. The increase in income from continuing operations as compared to prior year was due primarily to:

- favorable allowance for funds used during construction (AFUDC) at the Utilities;
- increased retail base rates at PEF;
- higher wholesale revenues at PEF;
- lower purchased power capacity costs at PEC due to the expiration of a power buyback agreement; and
- favorable net retail customer growth and usage at PEC.

Partially offsetting these items were:

- higher interest expense at PEF;
- higher income tax expense due to the benefit from the closure of certain federal tax years and positions in 2007;
- unfavorable net retail customer growth and usage at PEF;
- unfavorable weather at PEC;
- higher investment losses of certain employee benefit trusts at PEF and Corporate and Other resulting from the decline in market conditions; and
- higher depreciation and amortization expense at PEF excluding prior year recoverable storm amortization at PEF.

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 North Carolina Clean Smokestacks Act (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 AFUDC equity at the Utilities;
- favorable net retail customer growth and usage at the Utilities; and
- higher wholesale revenues at PEF.

Partially offsetting these items were:

- higher operation and maintenance (O&M) expenses at the Utilities primarily due to higher plant 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. 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.

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

(in millions)	2008	Change	2007	Change	2006
PEC	**$ 531**	$ 33	$ 498	$ 44	$ 454
PEF	**383**	68	315	(11)	326
Total segment profit	**914**	101	813	33	780
Corporate and Other	**(141)**	(21)	(120)	109	(229)
Total income from continuing operations	**773**	80	693	142	551
Discontinued operations, net of tax	**57**	246	(189)	(209)	20
Net income	**$ 830**	$ 326	$ 504	$ (67)	$ 571

PROGRESS ENERGY CAROLINAS

PEC contributed segment profits of $531 million, $498 million and $454 million in 2008, 2007 and 2006, respectively. The increase in profits for 2008 as compared to 2007 is primarily due to lower purchased power capacity costs due to the expiration of a power buyback agreement, favorable AFUDC and favorable net retail customer growth and usage, partially offset by the unfavorable impact of weather and lower excess generation revenues

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 net retail customer growth and usage, partially offset by higher O&M expense 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 revenue tables below present the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We and PEC consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, a portion of purchased power expenses and other pass-through 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 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

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

(in millions) Customer Class	2008	% Change	2007	% Change	2006
Residential	$ 1,626	0.8	$ 1,613	10.3	$ 1,462
Commercial	1,127	1.8	1,107	10.3	1,004
Industrial	725	1.3	716	0.7	711
Governmental	104	6.1	98	7.7	91
Total retail revenues	3,582	1.4	3,534	8.1	3,268
Wholesale	737	(2.3)	754	4.7	720
Unbilled	8	–	–	–	(1)
Miscellaneous	101	5.2	96	(2.0)	98
Total electric revenues	4,428	1.0	4,384	7.3	4,085
Less: Fuel and other pass-through revenues	(1,625)	–	(1,547)	–	(1,336)
Revenues excluding fuel and other pass-through revenues	$ 2,803	(1.2)	$ 2,837	3.2	$ 2,749

PEC's revenues, excluding fuel and other pass-through revenues of $1 625 billion and $1 547 billion for 2008 and 2007, respectively, decreased $34 million. The decrease in revenues was due primarily to lower wholesale revenues, excluding fuel and other pass-through revenues, of $45 million and the $28 million unfavorable impact of weather, partially offset by the $34 million favorable impact of net retail customer growth and usage. The lower wholesale revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer.

The current recession in 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 impacted by the recession as significantly as PEF. However, PEC has experienced some decline in the rate of residential and commercial sales growth. We cannot predict the severity of the recession, how long it may last or the extent to which it may impact PEC's revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates resulting from higher fuel and other recoverable costs.

PEC's revenues, excluding fuel and other pass-through revenues of $1.547 billion and $1.336 billion for 2007 and 2006, respectively, increased $88 million. The increase in revenues was due primarily to the $57 million favorable impact of weather and a $22 million favorable impact of net retail customer growth and usage. Weather had a favorable impact as cooling degree days were 20 percent higher than 2006 and 16 percent higher than normal. The favorable retail customer growth and usage was driven by a net 28,000 increase in the average number of customers for 2007 compared to 2006, partially offset by lower average usage per retail customer.

PEC's electric energy sales in kilowatt -hours (kWh) and the percentage change by year and by customer class were as follows:

(in millions of kWh) Customer Class	**2008**	% Change	2007	% Change	2006
Residential	**17,000**	(1.2)	17,200	5.8	16,259
Commercial	**13,941**	(0.6)	14,032	5.0	13,358
Industrial	**11,388**	(4.3)	11,901	(4.0)	12,393
Governmental	**1,466**	1.9	1,438	1.3	1,419
Total retail energy sales	**43,795**	(1.7)	44,571	2.6	43,429
Wholesale	**14,329**	(6.4)	15,309	5.0	14,584
Unbilled	**(8)**	–	(55)	–	(137)
Total kWh sales	**58,116**	(2.9)	59,825	3.4	57,876

Retail revenues increased 1.4 percent for 2008 despite a decrease in 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. Industrial electric energy sales decreased in 2008 compared to 2007, 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.

Wholesale revenues decreased less than wholesale energy sales for 2008 due to the impact of increased fuel revenues as a result of higher energy costs.

Industrial electric energy sales decreased in 2007 compared to 2006 primarily due to the downward trends in textile manufacturing and residential construction previously discussed. 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.

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 $1.692 billion for 2008, which represents a $9 million increase compared to 2007. Purchased power expense increased $44 million to $346 million compared to prior year. The increase is primarily due to increased economical purchases in 2008 of $78 million, partially offset by the $38 million impact from the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Fuel used in electric generation decreased $35 million to $1.346 billion primarily due to a $116 million decrease in deferred fuel expense, partially offset by increased current year fuel costs of $81 million. The decrease in deferred fuel expense was primarily driven by a $64 million impact from the implementation of the North Carolina comprehensive energy legislation (See "Other Matters – Regulatory Environment") and a $49 million impact related to under-recovered fuel costs. Deferred fuel expense was higher in 2007 primarily due to the collection of fuel costs from customers that had been previously under-recovered. The increase in current year fuel costs of $81 million was primarily due to an increase in coal prices, partially offset by the impacts of lower system requirements and a change in the generation mix. See "PEC – Fuel and Purchased Power" in Item 1, "Business," for a summary of average fuel costs.

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 primarily due to a $156 million increase in fuel costs and a $54 million increase in deferred fuel expense. Fuel costs 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. Purchased power expense decreased $32 million to $302 million compared to 2006. The decrease in purchased power is due to lower co-generation as a result of contract changes with one of PEC's co-generators.

Operation and Maintenance

O&M expense was $1.030 billion for 2008, which represents a $6 million increase compared to 2007. This increase is driven primarily by a $33 million increase in nuclear expenses, of which $18 million relates to refurbishments, preventative maintenance and incremental outage expenses at Brunswick Nuclear Plant (Brunswick). Additionally, O&M increased due to a $7 million increase in estimated environmental remediation expenses (See Note 21A), partially offset by $19 million lower employee benefits as discussed below and $16 million lower nuclear plant outage and maintenance costs (primarily due to two nuclear refueling and maintenance outages in the current year compared to three in the prior year).

O&M expense was $1.024 billion for 2007, which represents a $94 million increase compared to 2006. This increase is driven primarily by the $49 million higher nuclear plant outage and maintenance costs (partially due to three nuclear refueling and maintenance outages in 2007 compared to two in 2006) and $29 million due to higher employee benefit costs. The higher employee benefit costs are primarily due to the impact from changes in stock-based compensation plans implemented in 2007 and higher relative employee incentive goal achievement in 2007 compared to 2006.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $518 million for 2008, which represents a $1 million decrease compared to 2007. This decrease is primarily attributable to $19 million lower Clean Smokestacks Act amortization, $8 million lower GridSouth Transco, LLC (GridSouth) amortization (See Note 7D) and $3 million lower storm deferral amortization, partially offset by $15 million higher depreciation associated with the accelerated cost-recovery program for nuclear generating assets (See Note 7B) and the $15 million impact of depreciable asset base increases. In accordance with a 2008 regulatory order, PEC has ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful life of the assets (See Note 7B).

Depreciation, amortization and accretion 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), an $11 million charge to reduce PEC's 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.

Total Other Income, Net

Total other income, net was $43 million for 2008, which represents a $6 million increase compared to 2007. This increase is primarily due to $17 million favorable AFUDC equity related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs, partially offset by $9 million lower interest income resulting from lower average eligible deferred fuel balances and lower temporary investment balances.

Total other income, net was $37 million 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 eligible construction projects.

Total Interest Charges, Net

Total interest charges, net was $207 million for 2008, which represents a $3 million decrease compared to 2007. This decrease is primarily due to the $7 million favorable AFUDC debt related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs and the $4 million impact of a decrease in average long-term debt, offset by an $11 million interest benefit resulting from the resolution of tax matters in 2007.

Total interest charges, net was $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 eligible construction project costs, partially offset by $2 million higher interest related to higher variable rates on pollution control obligations.

Income Tax Expense

Income tax expense was $298 million, $295 million and $265 million in 2008, 2007 and 2006, respectively. The $3 million income tax expense increase in 2008 compared to 2007 is primarily due to the $14 million impact of higher pre-tax income and the $5 million impact related to the deduction for domestic production activities, partially offset by the $7 million tax impact of employee stock-based benefits and the $7 million impact of the increase in AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense. The $30 million income tax expense increase in 2007 compared to 2006 is primarily due to the impact of higher pre-tax income.

PROGRESS ENERGY FLORIDA

PEF contributed segment profits of $383 million, $315 million and $326 million in 2008, 2007 and 2006, respectively. The increase in profits for 2008 as compared to 2007 is primarily due to favorable AFUDC, increased retail base rates and higher wholesale revenues, partially offset by higher interest expense, unfavorable net retail customer growth and usage, higher depreciation and amortization expense excluding prior year recoverable storm amortization, and higher investment losses of certain employee benefit trusts.

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 expense, and higher depreciation and amortization expense excluding recoverable storm amortization, partially offset by favorable AFUDC and higher wholesale sales.

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	2008	% Change	2007	% Change	2006
Residential	**$2,274**	(3.8)	$2,363	0.1	$2,361
Commercial	**1,128**	(2.2)	1,153	0.1	1,152
Industrial	**308**	(3.1)	318	(8.1)	346
Governmental	**293**	(3.6)	304	1.0	301
Revenue sharing refund	**–**	–	–	–	1
Total retail revenues	**4,003**	(3.3)	4,138	(0.6)	4,161
Wholesale	**547**	26.0	434	36.1	319
Unbilled	**3**	–	4	–	(5)
Miscellaneous	**178**	2.9	173	5.5	164
Total electric revenues	**4,731**	(0.4)	4,749	2.4	4,639
Less: Fuel and other pass-through revenues	**(2,978)**	–	(3,109)	–	(3,038)
Revenues excluding fuel and other pass-through revenues	**$1,753**	6.9	$1,640	2.4	$1,601

PEF's revenues, excluding fuel and other pass-through revenues of $2.978 billion and $3.109 billion for 2008 and 2007, respectively, increased $113 million. The increase in revenues was primarily due to base rate increases and increased wholesale revenues, partially offset by unfavorable net retail customer growth and usage. The increase in base rates was $90 million; Hines 4 being placed in service contributed $53 million, and the transfer of Hines 2 cost recovery from the fuel clause to base rates contributed $37 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 $49 million primarily due to several new and amended contracts. PEF's base rate and wholesale revenue favorability was partially offset by the unfavorable net retail customer growth and usage impact of $32 million.

The current recession in the United States has contributed to a slowdown in customer growth and usage in PEF's service territory. PEF's average number of customers was the same for 2008 and 2007 compared to a net 23,000 increase in the average number of customers for 2007 compared to 2006. We cannot predict the severity of the recession, how long it may last or the extent to which it may further impact PEF's revenues. In the future, PEF's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates resulting from higher fuel and other recoverable costs.

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 was primarily due to increased wholesale revenues, favorable net retail customer growth and usage, and other miscellaneous service revenues. Wholesale revenues, excluding fuel and other pass-through revenues, increased $29 million primarily due to the $21 million impact of increased capacity under contract with a major customer. The favorable net retail customer growth and usage impact of $7 million was driven by a net 23,000 increase in the average number of customers for 2007, compared to 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.

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

(in millions of kWh) Customer Class	2008	% Change	2007	% Change	2006
Residential	**19,328**	(2.9)	19,912	(0.5)	20,021
Commercial	**12,139**	(0.4)	12,183	1.7	11,975
Industrial	**3,786**	(0.9)	3,820	(8.2)	4,160
Governmental	**3,302**	(1.9)	3,367	2.8	3,276
Total retail energy sales	**38,555**	(1.9)	39,282	(0.4)	39,432
Wholesale	**6,758**	14.0	5,930	30.8	4,533
Unbilled	**(123)**	–	88	–	(234)
Total kWh sales	**45,190**	(0.2)	45,300	3.6	43,731

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

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 $2.628 billion in 2008, which represents an $18 million decrease compared to 2007. Fuel used in electric generation decreased $89 million to $1.675 billion due to a $381 million decrease in deferred fuel expense, partially offset by increased current year fuel costs of $293 million. The decrease in 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. With the increase in fuel prices experienced in 2008, PEF successfully sought a mid-course fuel correction, but the revised fuel factors were not effective until August 2008. The increase in current year fuel costs was primarily due to increased fuel prices and a change in generation mix. Purchased power expense increased $71 million to $953 million compared to 2007. This increase is primarily due to increased current year purchases of $37 million as a result of higher fuel costs and an increase in the recovery of deferred capacity costs of $34 million. See "PEF – Fuel and Purchased Power" in Item 1, "Business," for a summary of average fuel costs.

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 2007 fuel costs due primarily to an increase in oil and natural gas prices. Deferred fuel expense was higher in 2006 primarily due to the collection of fuel costs from customers that had been previously under-recovered

Operation and Maintenance

O&M expense was $813 million in 2008, which represents a $21 million decrease compared to 2007. The decrease is primarily due to $24 million lower environmental cost recovery clause (ECRC) costs due to a decrease in the current year rates resulting from prior year over-recovery, $12 million lower employee benefit costs as discussed below, and $12 million lower sales and use tax audit adjustment, partially offset by $19 million related to replenishment of storm damage reserves, which began in August 2007 and continued through August 2008 in accordance with a regulatory order, and $11 million higher plant outage and maintenance costs. The ECRC and replenishment of storm damage reserves expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates decreased $19 million compared to the same period in 2007

O&M expense was $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 ECRC and energy conservation cost recovery clause (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 the impact from changes in stock-based compensation plans implemented in 2007 and higher relative employee incentive goal achievement in 2007 compared to 2006. The ECRC, ECCR and storm damage reserve expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates increased $63 million compared to the same period in 2006.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $306 million for 2008, which represents a decrease of $60 million compared to 2007, primarily due to $75 million lower amortization of unrecovered storm restoration costs and a $7 million write-off in 2007 of leasehold improvements primarily related to vacated office space, partially offset by the $20 million impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a storm-recovery surcharge and, therefore, had no material impact on earnings (See Note 7C)

Depreciation, amortization and accretion expense was $366 million for 2007, which represents a decrease of $38 million compared to 2006, primarily due to $47 million lower amortization of unrecovered 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. As noted above, storm restoration costs amortization had no material impact on earnings.

Other

Other operating expense was a gain of $5 million in 2008, $8 million of expense in 2007 and a gain of $2 million in 2006. The $10 million difference between 2006 and 2007 and the $13 million difference between 2008 and 2007 are primarily due to the $12 million impact of a 2007 FPSC order requiring PEF to refund disallowed fuel costs to its ratepayers (See Note 7C).

Total Other Income, Net

Total other income, net was $94 million for 2008, which represents a $46 million increase compared to 2007. This increase is primarily due to $54 million favorable AFUDC equity related to eligible construction project costs, partially offset by $11 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions. We expect AFUDC equity to continue to increase in 2009, primarily due to increased spending on environmental initiatives and other eligible construction projects. See "Future Liquidity and Capital Resources – Capital Expenditures."

Total other income, net 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 eligible construction project costs, partially offset by $5 million lower interest income on unrecovered storm restoration costs.

Total Interest Charges, Net

Total interest charges, net was $208 million in 2008, which represents an increase of $35 million compared to 2007. The increase in interest charges is primarily due to the $60 million impact of an increase in average long-term debt, partially offset by $16 million favorable AFUDC debt related to costs associated with eligible construction projects and $7 million interest benefit resulting from the resolution of tax matters in 2008.

Total interest charges, net was $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 eligible construction project costs

Income Tax Expense

Income tax expense was $181 million, $144 million and $193 million in 2008, 2007 and 2006, respectively. The $37 million income tax expense increase in 2008 compared to 2007 is primarily due to the $40 million impact of higher pre-tax income compared to the prior year, $6 million benefit related to the closure of certain federal tax years and positions in the prior year, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's most recent base rate agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense. 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, the $16 million impact of tax adjustments and the $9 million impact of favorable AFUDC equity discussed above. The tax adjustments are primarily related to the $10 million impact of changes in income tax estimates and the $6 million favorable impact related to the closure of certain federal tax years and positions.

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)	2008	Change	2007	Change	2006
Other interest expense	$ **(223)**	$ (18)	$ (205)	$ 54	$ (259)
Contingent value obligations	**–**	2	(2)	23	(25)
Other income tax benefit	**83**	(22)	105	(14)	119
Other expense	**(1)**	17	(18)	46	(64)
Corporate and Other after-tax expense	$ **(141)**	$ (21)	$ (120)	$ 109	$ (229)

Other interest expense, which includes elimination entries, increased $18 million for 2008 compared to 2007 primarily due to a $6 million prior year benefit related to the closure of certain federal tax years and positions and a decrease in the interest allocated to discontinued operations. The decrease in interest allocated to discontinued operations resulted from the allocations of interest expense in early 2007 to operations that were sold later in 2007. An immaterial amount and $13 million of interest expense were allocated to discontinued operations for 2008 and 2007, respectively.

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.

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 (See Note 15). At December 31, 2008 and 2007, the CVOs had a fair value of $34 million and at December 31, 2006, the CVOs had a fair value of $32 million. Progress Energy recorded unrealized losses of $2 million and $25 million for 2007 and 2006, respectively, to record the changes in fair value of the CVOs, which had average unit prices of $0.35 at December 31, 2008 and 2007 and $0.33 at December 31, 2006.

Other income tax benefit decreased $22 million for 2008 compared to 2007 primarily due to the $14 million prior year benefit related to the closure of certain federal tax years and positions (See Note 14) and the net $3 million impact recorded in 2008 for a state net operating loss carry forward. We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures, Inc.'s (PVI) nonregulated generation facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate.

Other income tax benefit decreased $14 million for 2007 compared to 2006 primarily due to decreased pre-tax expense at the Parent primarily as a result of the $58 million impact of the early retirement of debt in 2006, partially offset by the $18 million impact of taxes on interest allocated to discontinued operations, the $14 million impact related to the closure of certain federal tax years and positions (See Note 14), the $5 million impact related to the deduction for domestic production activities and the $3 million impact of changes in income tax estimates.

For 2008, other expense was $1 million compared to $18 million in 2007. The $17 million decrease is primarily due to $15 million decreased indirect corporate overhead due to divestitures completed in 2007 and $12 million decreased legal expenses, partially offset by $8 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

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 20) 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 Communications, Inc. stock subsequent to the sale of PT LLC in 2006 (See Note 3F) and the $14 million increase in interest income on temporary investments due to proceeds from the sale of nonregulated businesses

DISCONTINUED OPERATIONS

Over the last several years we have reduced our business risk by exiting substantially all of our nonregulated businesses to focus on the core operations of the Utilities. Consequently, the composition of other continuing segments has been impacted by these divestitures. See Note 3 for additional information related to discontinued operations.

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 coal terminals had 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. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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. 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 $19 million and $83 million for the years ended December 31, 2008 and 2007, respectively. Net losses from discontinued operations for Terminals and synthetic fuels businesses were $37 million for the year ended December 31, 2006

The decrease in net earnings from discontinued operations of $83 million for the year ended December 31, 2007, to $19 million for the year ended December 31, 2008, is primarily due to the 2007 expiration of the tax credit program.

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, 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.

COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels Corporation (Progress Fuels) subsidiaries engaged in the coal mining business for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. These assets included Powell Mountain Coal Co. and Dulcimer Land Co., which consisted of approximately 30,000 acres in Lee County, Va., and Harlan County, Ky. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets.

On May 1, 2006, we sold certain net assets of three of our coal mining businesses 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 for the sale of these assets.

Net losses from discontinued operations for the coal mining business were $9 million, $11 million and $4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary 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 included approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the nonregulated 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 years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax loss and reversed $18 million after tax of the impairment recorded in 2006, respectively.

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 represented 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 represented 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 the divestiture of CCO and the Georgia Contracts for general corporate purposes.

CCO's operations generated net losses from discontinued operations of $3 million, $283 million and $57 million in 2008, 2007 and 2006, 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. Net losses from discontinued operations in 2006 primarily represent the $64 million pre-tax impairment loss ($42 million after-tax) on goodwill recognized in the first quarter of 2006.

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., Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale were 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.

Gas operations generated net earnings from discontinued operations of $4 million and $82 million for the years ended December 31, 2007 and 2006, respectively. Net earnings from discontinued operations during 2006 were impacted by increased production, higher market prices and mark-to-market gains on gas hedges.

CCO – DESOTO AND ROWAN GENERATION FACILITIES

On May 8, 2006, we entered into definitive agreements to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (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. DeSoto and Rowan operations generated combined net earnings from discontinued operations of $10 million for the year ended December 31, 2006.

PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of PT LLC to Level 3 Communications, Inc. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 Communications, Inc. 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 20 for a discussion of the subsequent sale of the Level 3 Communications, Inc. 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 losses from discontinued operations for PT LLC were $2 million for the year ended December 31, 2006.

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 transported 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 years ended December 31, 2008 and 2007, we recorded an additional gain of $1 million and $2 million, respectively, primarily related to the expiration of indemnifications.

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

PROGRESS RAIL

We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2008, we recorded an after-tax gain on disposal of $2 million. During the year ended December 31, 2006, we recorded an after-tax loss on disposal of $6 million. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods.

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.

IMPACT OF UTILITY REGULATION

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.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. 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. 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. The carrying values of our total utility plant, net at December 31 were as follows:

(in millions)	2008	2007
Progress Energy	$ 18,293	$ 16,605
PEC	9,385	8,880
PEF	8,790	7,600

As discussed in Note 13, our financial assets and liabilities are primarily comprised of derivative financial instruments and marketable debt and equity securities held in our nuclear decommissioning trusts. Substantially all unrealized gains and losses on derivatives and all unrealized gains and losses on nuclear decommissioning trust investments are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Therefore, the impact of fair value measurements from recurring financial assets and liabilities on our or the Utilities' earnings is not significant.

ASSET RETIREMENT OBLIGATIONS

As discussed in Note 4D, we account for Asset Retirement Obligations (AROs), which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) and Financial Accounting Standards Board interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143" (FIN 47). 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 the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability.

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, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71).

Progress Energy's, PEC's and PEF's total AROs at December 31, 2008, were $1.471 billion, $1.122 billion, and $349 million, respectively. We calculated the present value of our AROs based on estimates which are dependent on subjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 96 percent, 98 percent, and 92 percent respectively, of Progress Energy's, PEC's and PEF's total AROs at December 31, 2008. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies 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. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized.

PEC obtained updated cost studies for its nuclear plants in 2004, using 2004 cost factors. PEC plans to update its site-specific cost studies in 2009. If the site-specific cost estimates increased by 10 percent, PEC's AROs would have increased by $92 million. If the inflation adjustment increased 25 basis points, PEC's AROs would have increased by $83 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEC's AROs by $73 million.

PEF obtained an updated cost study for its nuclear plant in 2008, using 2008 cost factors. If the site-specific cost estimates increased by 10 percent, PEF's AROs would have increased by $32 million. If the inflation adjustment increased 25 basis points, PEF's AROs would have increased by $25 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEF's AROs by $23 million.

GOODWILL

As discussed in Note 8, we account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2008 and 2007, 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, 2008 and 2007, 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, interest rates, growth rates or the timing of market equilibrium, could result in a future impairment charge to goodwill.

We monitor for events or circumstances that may indicate an interim goodwill impairment test is necessary. We have considered the distress in the financial markets during 2008 and the impact on the fair value of our reporting units and concluded an interim goodwill impairment test was not necessary.

UNBILLED REVENUE

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. Amounts recorded as receivables on the Balance Sheets at December 31 related to unbilled revenues were as follows:

(in millions)	2008	2007
Progress Energy	$ **182**	$ 175
PEC	**120**	111
PEF	**62**	59

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 14, we account for the effects of income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), and FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

Under SFAS No. 109, deferred income tax assets and liabilities are provided, representing the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. In accordance with FIN 48, the uncertainty and judgment involved in the determination and filing of income taxes is accounted for 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.

PENSION COSTS

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

Due to a slight 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 calculate the present value of future benefit payments, we increased the discount rate to approximately 6.30% at December 31, 2008, from approximately 6.20% at December 31, 2007.

which will not significantly affect 2009 pension costs. 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. Consistent with general market conditions, our plan assets performed poorly in 2008 with returns of approximately (32)%. That negative asset performance will result in increased pension costs in 2009, all other factors remaining constant. In addition, contributions to pension plan assets in 2008 and 2009 will result in decreased pension costs in 2009 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2009 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2009 will be $85 million to $95 million, compared with $14 million recognized in 2008.

We have pension plan assets with a fair value of approximately $1.3 billion at December 31, 2008. 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. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 25 basis point change in the expected rate of return for 2008 would have changed 2008 pension costs by approximately $5 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.

Since PEC and PEF participate in our pension plans, the general discussion above applies to PEC and PEF. PEC and PEF have not completed evaluating their 2009 pension costs. PEC estimates that the total cost recognized for pensions in 2009 will be $20 million to $25 million, compared with $23 million recognized in 2008. A 25 basis point change in the expected rate of return for 2008 would have changed PEC's 2008 pension costs by approximately $2 million. PEF estimates that the total cost recognized for pensions in 2009 will be $50 million to $55 million, compared with a pension credit of $20 million recognized in 2008. A 25 basis point change in the expected rate of return for 2008 would have changed PEF's 2008 pension costs by approximately $2 million.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Our 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. As discussed in "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized.

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.

As a registered holding company, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) for, among other things, the establishment of intercompany extensions of credit (utility and non-utility money pools). Our subsidiaries participate in internal money pools, operated by Progress Energy, to more effectively utilize cash resources and reduce outside short-term borrowings. The utility money pool allows the 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.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $2.6 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from the Parent. Although the Utilities did not pay dividends to the Parent in 2008, PEC expects to pay dividends to the Parent in 2009. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends that the Utilities may pay to the Parent from year-to-year. We do not currently expect changes to the Parent's common stock dividend policy.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, equity offerings, and limited ongoing sales of common stock from our Investor Plus Stock Purchase Plan, employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2009. For the fiscal year 2009, we expect to realize approximately $600 million in the aggregate from the sale of stock through marketed and ongoing equity sales.

We have addressed the challenges presented by current financial market conditions and will continue to monitor the credit markets to maintain an appropriate level of liquidity. Despite the tightened credit market that began with the extreme market turmoil in the third quarter of 2008, we have been able to issue additional equity and short- and long-term debt.

As shown in the table that follows, we have a number of financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as back-ups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had $600 million of outstanding borrowings under its credit facility. In addition, at December 31, 2008, the Parent, PEC and PEF had outstanding commercial paper balances of $69 million, $110 million and $371 million, respectively, and the Parent had issued $30 million of letters of credit, which were supported by the revolving credit agreement (RCA). Based on these outstanding amounts at December 31, 2008, there was $850 million available for additional borrowings. During February 2009, the Parent repaid $100 million of the outstanding balance under its credit facility.

(in millions)	Total Commitment			
Credit Provider	Progress Energy	Parent	PEC	PEF
JPMorgan Chase Bank, N.A.	$ 225.0	$ 141.0	$ 44.0	$ 40.0
Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch	200.0	95.0	45.0	60.0
Barclays Bank PLC	190.5	100.0	20.5	70.0
Bank of America, N.A.	190.0	98.0	22.0	70.0
Citibank, N.A.	180.0	111.0	34.0	35.0
Wachovia Bank, N.A.	175.5	53.0	82.5	40.0
Royal Bank of Scotland plc	169.0	92.0	77.0	–
The Bank of New York Mellon	120.0	35.0	40.0	45.0
SunTrust Bank	115.0	50.0	20.0	45.0
Morgan Stanley Bank	100.0	50.0	50.0	–
William Street Commitment Corporation	100.0	100.0	–	–
Deutsche Bank AG, New York Branch	95.0	50.0	–	45.0
UBS Loan Finance LLC	80.0	80.0	–	–
~~BNP Paribas~~	~~50.0~~	~~50.0~~	~~–~~	~~–~~
Branch Banking & Trust Co.	25.0	25.0	–	–
First Tennessee Bank N.A.	15.0	–	15.0	–
Total commitment	$ 2,030.0	$1,130.0	$450.0	$450.0

At December 31, 2008, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of partners. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2008, all of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2008, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for both the Parent and PEC. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2008, all of the Parent's and PEC's open pay-fixed forward starting swaps were in a net mark-to-market liability position. See Note 17B for additional information with regard to our interest rate derivatives.

Our pension trust funds and nuclear decommissioning trust funds are managed by a number of financial institutions, and the assets being managed are diversified in order to limit concentration risk in any one institution or business sector.

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 2008 AS COMPARED TO 2007 AND 2007 AS COMPARED TO 2006

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2008, 2007 and 2006. Net cash provided by operating activities for the three years ended December 31, 2008, 2007 and 2006, was $1.218 billion, $1.252 billion and $2.001 billion, respectively.

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $34 million decrease in operating cash flow was primarily due to a $450 million decrease in the recovery of fuel costs due to the 2008 under-recovery driven by rising fuel costs, compared to an over-recovery of fuel costs during the corresponding period in 2007; $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $55 million in net refunds of cash collateral in 2007, primarily at PEF; and a $226 million increase in inventory purchases, primarily coal, driven by higher prices. These impacts were partially offset by a $419 million increase from accounts receivable, primarily related to our divested CCO operations and former synthetic fuels businesses; the $347 million payment made in 2007 to exit the Georgia contracts (See Note 3C); a $117 million increase from accounts payable; and a $106 million increase from income taxes, net. The increase from accounts receivable was primarily driven by the settlement of $234 million of derivative receivables related to derivative contracts for our former synthetic fuels businesses (See Note 17A). The increase from income taxes, net was largely due to $252 million in income tax payments made in 2007 related to the sale of Gas (See Note 3D), partially offset by income tax impacts at PEC. The change in accounts payable was primarily related to our divested operations.

Net cash provided by 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 3C); 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 2007 compared to $47 million in net cash payments in 2006 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.

In 2008, 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.

INVESTING ACTIVITIES

Net cash (used) provided by investing activities for the three years ended December 31, 2008, 2007 and 2006, was $(2.541) billion, $(1.457) billion and $127 million, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.534 billion and $2.199 billion in 2008 and 2007, respectively, or approximately 100 percent of consolidated capital expenditures in both 2008 and 2007. 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 $72 million in 2008 and $675 million in 2007, cash used in investing activities increased by $481 million. The increase in 2008 was primarily due to a $341 million increase in gross property additions at the Utilities, primarily at PEF, and a $95 million decrease in net purchases of available-for-sale securities and other investments. The increase in capital expenditures for utility property additions at PEF was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

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 in 2007 as compared to 2006. 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 was 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.

During 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds of $63 million from the sale of Terminals and Coal Mining (See Notes 3A and 3B).

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 3C), 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 3D), $405 million from the sale of DeSoto and Rowan (See Note 3E), approximately $70 million from the sale of PT LLC (See Note 3F), approximately $27 million from the sale of certain net assets of the coal mining business (See Note 3B), and approximately $16 million from the sale of Dixie Fuels (See Note 3G).

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2008, 2007 and 2006, was $1.248 billion, $195 million and $(2.468) billion, respectively. See Note 11 for details of debt and credit facilities.

The increase in net cash provided by financing activities for 2008 compared to 2007 is primarily due to PEF's $1.475 billion net proceeds and PEC's $322 million net proceeds from the issuance of long-term debt in 2008 discussed below, compared to $739 million in net proceeds in 2007. Additionally, net short-term debt increased in 2008 compared to 2007 due to $600 million in outstanding borrowings under the Parent's RCA, and outstanding commercial paper issuances of $69 million at the Parent, $110 million at PEC and $371 million at PEF, compared to outstanding commercial paper issuances of $201 million at the Parent in 2007. The increase in proceeds from long-term debt issuances was offset by $877 million in long-term debt retirements in 2008; $176 million in payments on short-term debt; and $85 million in cash distributions to owners of minority interests of consolidated subsidiaries primarily related to the settlement of Ceredo Synfuel LLC's (Ceredo) synthetic fuels derivatives contracts (See Note 17A).

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.

Our financing activities are described below.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.

- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding money pool balance and for general corporate purposes

2008

- 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 RCAs 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 (See "Credit Facilities and Registration Statements").

- 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 6.65% 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, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").

- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.

- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. A portion of the RCA borrowings was repaid with proceeds from the January 2009 equity issuance, and we will continue to monitor the commercial paper and short-term credit markets to determine when to repay the remaining balance of the RCA loan, while maintaining an appropriate level of liquidity.

- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2008, the dividends paid on common stock were approximately $642 million.

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 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.

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $151 million in proceeds from its Investor Plus Stock Purchase Plan and its equity incentive plans. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million issued for 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 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.

- 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.

- 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.

- 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 equity incentive plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million issued for the 401(k) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 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, 2008, 2007 and 2006. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has 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, 2008, we have carried forward $799 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.

The absence of cash flow 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.

We expect to be able to meet our future liquidity needs through cash from operations, commercial paper issuance, availability under our credit facilities, long-term debt financings and equity offerings. We may also use periodic ongoing sales of common stock 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. As a result of financial and economic conditions in 2008, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. In November 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. A portion of the RCA was repaid with proceeds from the January 2009 equity issuance, and we will continue to monitor the commercial paper and short-term credit markets to determine when to repay the remaining balance of the RCA loan, while maintaining an appropriate level of liquidity. If liquidity conditions deteriorate further 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 extending the term and amount of our borrowings under the Parent's RCA, issuing short-term floating rate notes, and/or issuing long-term debt.

Progress Energy and its subsidiaries have approximately $10.659 billion in outstanding long-term debt. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. Bond insurance generally allows companies to issue tax-exempt bonds with the insurance company's higher credit rating. Ambac Assurance Corporation (Ambac) insures PEC's bonds and Syncora Guarantee Inc., formerly XL Capital Assurance, Inc. (Syncora), insures PEF's bonds.

Auctions for the tax-exempt bonds have seen an increase in failures and the relative level of the interest rates that are periodically reset at each auction. In the event of a failed auction, the bond holders cannot sell their bonds and the interest rate is calculated based on a multiple of a standard market index such as the Securities Industry and Financial Markets Association's Municipal Swap Index or the London Interbank Offered Rate (LIBOR). The interest rates for most of PEC's portfolio of tax-exempt securities reset based on the Securities Industry and Financial Markets Association's Municipal Swap Index. The interest rates for PEF's portfolio of tax-exempt securities reset based on one-month LIBOR. The multiple on our auction rate bonds is stable as long as the bonds are rated A3 or higher by Moody's Investors Service, Inc. (Moody's) or A- or higher by Standard & Poor's Rating Services (S&P). If the insurance company's rating falls below the Utilities' ratings, then the bonds will be rated at the Utilities' senior secured debt rating, which is currently A2 by Moody's and A- by S&P for both Utilities. Since the initial downgrades of Syncora and Ambac in 2008 by Moody's and S&P, which caused an increase in market volatility and an increase in interest rates, subsequent downgrades did not materially impact the reset rates of the tax-exempt bonds. We do not expect further rating actions on Syncora and Ambac to materially impact the reset rates of the tax-exempt securities.

Future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may move our tax-exempt bonds below A3/A-. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $130 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets in 2009 (See Note 16).

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," 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. As discussed in "Environmental Matters – Environmental Compliance Cost Estimates," the Utilities are continuing construction of in-process emission control projects. On December 18, 2008, PEF and the Florida Department of Environmental Protection (FDEP) announced an agreement under which PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and complete construction of its emission control projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5). CR1 and CR2 will be retired after the second proposed Levy nuclear unit completes its first fuel cycle, which is anticipated to be around 2020.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause. Due to commodity price changes since December 31, 2008, we have posted additional collateral with counterparties. At February 23, 2009, we had posted approximately $580 million of cash collateral compared to $340 million of cash collateral posted at December 31, 2008. The majority of our financial hedge agreements will settle in 2009 and 2010. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity.

The amount and timing of future sales of securities will depend on market conditions, operating cash flow 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.

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. Regulatory developments expected to have a material impact on our liquidity are discussed below.

As discussed further in Note 7 and in "Other Matters – Regulatory Environment," the Florida legislature passed comprehensive energy legislation that became law in 2008 and the South Carolina and North Carolina state legislatures passed energy legislation that became law in 2007. These laws may impact our liquidity over the long term. We cannot predict the impacts to our liquidity of complying with Florida's comprehensive energy legislation.

Among other provisions, the North Carolina and South Carolina 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. On February 29, 2008, the North Carolina Utilities Commission (NCUC) issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. Rates for the DSM and energy-efficiency clause and the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) clause will be set based on projected costs with true-up provisions.

PEC Cost-Recovery Clause

On June 26, 2008, the South Carolina Public Service Commission (SCPSC) approved PEC's request for an increase in the fuel rate charged to its South Carolina ratepayers, which provided for a $39 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. Residential electric bills increased by $5.86 per 1,000 kWh, or 6.1 percent, for fuel cost recovery effective July 1, 2008. At December 31, 2008, PEC's South Carolina deferred fuel balance was $15 million.

On November 14, 2008, the NCUC approved a settlement agreement between PEC, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR), Carolina Utility Customers Association (CUCA) and the NCUC Public Staff. Under the terms of the settlement agreement, PEC will collect $203 million of deferred fuel costs ratably over a three-year period beginning December 1, 2008, compared with a one-year recovery period proposed in PEC's original request. Amounts to be collected in years beginning December 1, 2009 and 2010, will bear interest at a rate equal to the five-year United States Treasury Note plus 150 basis points. Effective December 1, 2008, residential electric bills increased by $8.79 per 1,000 kWh, or 9.1 percent. At December 31, 2008, PEC's North Carolina deferred fuel balance was $321 million, of which $130 million is expected to be collected after 2009 and has been classified as a long-term regulatory asset.

PEC has begun implementing the requirements of North Carolina's comprehensive energy legislation passed in 2007, including a series of DSM and energy-efficiency programs and NC REPS requirements. Program costs are eligible for recovery and have been deferred. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

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 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.

On February 12, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2010. In its notice, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and stated that it intends to seek annual rate relief between $475 million to $550 million. PEF intends to file its case-in-chief on March 20, 2009. The request for increased base rates is based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems. If approved by the FPSC, the new base rates would increase residential bills by approximately $15.00 per 1,000 kWh, or 11 percent, effective January 1, 2010. We cannot predict the outcome of this matter

As part of its February 12, 2009 notification, PEF also informed the FPSC that it may seek additional rate relief in 2009, primarily driven by the addition of its repowered Bartow power plant, which is expected to begin commercial operation in June 2009 and decreased sales and higher pension costs impacted by the current financial and credit crises. We cannot predict the outcome of this matter.

PEF Cause Recovery Clause

On July 1, 2008, the FPSC approved recovery of PEF's $213 million projected year-end under-recovery of fuel costs, but allowed PEF to recover 50 percent in 2008 and 50 percent in 2009. Therefore, the increase in the fuel rate for the period August through December 2008 was $6.03 per 1,000 kWh. This increase was partially offset by the expiration of PEF's storm cost-recovery surcharge of $3.61 per 1,000 kWh effective August 2008. Consequently, beginning with the first billing cycle in August and including gross receipts tax, residential electric bills increased by $2.48 per 1,000 kWh, or 2.29 percent.

In November 2008, the FPSC approved PEF's request for an increase in residential electric bills of $27.28 per 1,000 kWh, or 24.7 percent, effective January 1, 2009. The increase in residential bills is primarily due to increases of $14.09 per 1,000 kWh for the projected recovery of fuel costs, $9.74 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause and $2.50 per 1,000 kWh for the projected recovery through the ECRC. The increase in the capacity cost-recovery clause is primarily the result of projected costs to be incurred in 2009 under the nuclear cost-recovery rule discussed below for the proposed Levy Units 1 and 2 and the CR3 uprate less the projected reduction in capacity costs. The increase in the ECRC is primarily due to the recovery of emission allowance costs (See Note 21B) and the return on assets expected to be placed in service in 2009.

On February 18, 2009, PEF filed a request with the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $207 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices, and to defer until 2010 the recovery of $200 million of Levy nuclear preconstruction costs, which the FPSC had authorized to be collected in 2009 as discussed below in "Nuclear Cost Recovery." If approved, the request would reduce residential customers' fuel charges by $6.90 per 1,000 kWh, and would reduce the nuclear cost-recovery charge by $7.80 per 1,000 kWh, starting with the first April billing cycle. Commercial and industrial customers would see similar reductions. We cannot predict the outcome of this matter.

On October 10, 2007, the FPSC issued an order requiring PEF to refund its ratepayers approximately $14 million, including interest, over a 12-month period beginning January 1, 2008. The refund was returned to the ratepayers through a reduction of prior year under-recovered fuel costs. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. A hearing on PEF's 2006 and 2007 coal purchases has been scheduled for April 13-15, 2009. On February 2, 2009, Florida's Office of Public Counsel (OPC) filed direct testimony in this hearing alleging that during 2006 and 2007, PEF collected excessive fuel costs and sulfur dioxide (SO_2) allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economic sources of coal at its CR4 and CR5 plants. 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 $22 million at December 31, 2008. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve 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 the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after 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. 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.

During 2008, PEF filed for recovery of costs incurred to uprate CR3 under Florida's comprehensive energy legislation and the FPSC's nuclear cost-recovery rule. The current project estimate of fully loaded costs for the multi-stage uprate is $364 million. On August 19, 2008, the FPSC granted PEF's petition to amend its request to recover costs for the nuclear uprate project under the nuclear cost-recovery rule.

As discussed further in Note 7 and "Other Matters – Nuclear," on August 12, 2008, the FPSC issued the final order granting PEF's need certification petition for its proposed Levy Units 1 and 2, together with the associated facilities, including transmission lines and substation facilities. The filed, nonbinding project cost estimate for Levy Units 1 and 2 is approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. On October 14, 2008, the FPSC voted to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

As discussed above in "PEF Cost-Recovery Clause," on February 18, 2009, PEF filed a request with the FPSC to defer the recovery of $200 million of Levy nuclear preconstruction costs.

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 2008.

As shown in the table that follows, 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. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2008**	2009	2010	2011
Regulated capital expenditures	$ **2,151**	$ 1,990	$ 1,890	$ 1,650
Nuclear fuel expenditures	**222**	260	250	310
AFUDC – borrowed funds	**(26)**	(40)	(30)	(40)
Other capital expenditures	**5**	30	30	30
Total before potential nuclear construction	**2,352**	2,240	2,140	1,950
Potential nuclear construction(a)(b)	**168**	260 – 560	460 – 660	750 – 950
Total	$ **2,520**	$ 2,500 – 2,800	$ 2,600 – 2,800	$ 2,700 – 2,900

(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, regulatory approval schedules, timing and escalation of project costs and the percentages of joint ownership.

(b) These expenditures, which are primarily at PEF, are subject to cost-recovery provisions in the Utilities' respective jurisdictions (See discussion under "Other Matters – Nuclear"). Forecasted potential nuclear construction expenditures for 2009, 2010 and 2011 include approximately $50 million, $130 million and $150 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.
The timing of the recovery of these expenditures could be impacted by PEF's February 2009 regulatory filings discussed above in "Regulatory Matters and Recovery of Costs."

Regulated capital expenditures for 2009, 2010 and 2011 in the table above include approximately $380 million, $230 million and $120 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2009, 2010 and 2011 include $80 million, $150 million and $120 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2009 and 2010 include $300 million and $80 million, respectively, at PEF. PEF does not have forecasted environmental compliance capital expenditures in 2011. 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

At December 31, 2008 and 2007, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. At December 31, 2007, 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 RCAs and available capacity at December 31, 2008:

(in millions)	Description	Total	Outstanding(a)	Reserved(b)	Available
Parent	Five-year (expiring 5/3/12)	$1,130	$ 600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$ 600	$580	$850

(a) In February 2009, the Parent repaid $100 million of its outstanding RCA borrowings.
(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had a total amount of $30 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 11 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 the Parent's RCA are based upon the credit rating of the Parent'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, 2008. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2008, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 11.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited 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.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount 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, 2008, PEC and PEF could issue up to $4.1 billion and $1.7 billion of first mortgage bonds, respectively, based on property additions and $1.5 billion and $256 million, respectively, based upon retirements of previously issued first mortgage bonds. On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. Therefore, given the effect of the January 2009 issuance and the application of proceeds, PEC could issue up to $1.3 billion of first mortgage bonds based upon retirements of previously issued first mortgage bonds.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

	2008	2007
Common stock equity	**42.4%**	45.6%
Preferred stock and minority interest	**0.5%**	1.0%
Total debt	**57.1%**	53.4%

CREDIT RATING MATTERS

As of February 23, 2009, the major credit rating agencies rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Parent			
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-	A-

(a) Guaranteed by the Parent and Florida Progress.

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

On November 5, 2008, S&P raised the senior unsecured debt rating for both PEC and PEF to BBB+ from BBB as a result of S&P reevaluating its application of notching criteria for U.S. investment-grade investor-owned utility operating company unsecured debt to better reflect the relatively strong recovery prospects of creditors in this sector.

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, 2008, we have issued $402 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 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, 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 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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. 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, 2008, 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 11)	$ 10,716	$ –	$ 1,406	$ 1,875	$ 7,435
Interest payments on long-term debt (b)	9,000	623	1,163	941	6,273
Capital lease obligations (c) (See Note 22B)	726	34	69	87	536
Operating leases (c) (See Note 22B)	1,367	48	52	117	1,150
Fuel and purchased power (d) (See Note 22A)	22,657	3,608	5,349	3,554	10,146
Other purchase obligations (e) (See Note 22A)	9,836	1,151	3,098	3,001	2,586
Minimum pension funding requirements (f)	1,162	130	426	235	371
Other postretirement benefits (g) (See Note 16A)	494	40	88	98	268
Uncertain tax positions (h) (See Note 14)	–	–	–	–	–
Other commitments (i)	119	13	27	26	53
Total	$ 56,077	$ 5,647	$ 11,678	$ 9,934	$ 28,818

(a) Our 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, 2008.

(c) Amounts include certain related executory cost commitments.

(d) 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 cost-recovery clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.

(e) Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership.

(f) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(g) Represents projected benefit payments for a total of 10 years related to our postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

(h) Uncertain tax positions of $104 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, 2009.

(i) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $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

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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. The synthetic fuels tax credit program expired at the end of 2007. Because we 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.

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code 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 one-year carry back period and a 20-year carry forward period.

Section 29 provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (Annual Average Price) exceeded a certain threshold value (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 were fully eliminated (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.

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 calculated the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency. Based on the respective Annual Average Price, our synthetic fuels tax credits generated during 2007 and 2006 were reduced by 67 percent and 33 percent, or approximately $138 million and $35 million, respectively.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition), were $1.891 billion, of which $1.092 billion has been used to offset regular federal income tax liability and $799 million is being carried forward as deferred tax credits.

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, the 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.

During the 2008 session, the Florida legislature passed comprehensive energy legislation, which became law on June 26, 2008. 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 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; (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; and (5) require the FPSC to analyze utility revenue decoupling and provide a report and recommendation to the governor and legislature by January 1, 2009. The FPSC concluded and recommended to the governor and legislature that no specific revenue decoupling program needs to be, or should be, implemented at this time. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until the rulemaking processes are completed, we cannot predict the costs of complying with the law.

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.

The Energy and Climate Action Team appointed by the governor developed recommendations through a stakeholder process and submitted its final report to the governor on October 15, 2008. The report's recommendations encourage the consideration of a cap-and-trade approach to reduce the state's greenhouse emissions and the development and implementation of energy-efficiency and conservation measures, a climate registry and a renewable portfolio standard (Florida RPS) of 20 percent by 2020. The FDEP's first workshop on the greenhouse gas cap-and-trade rulemaking was held December 11, 2008. The rulemaking is expected to continue through 2009, and the rule requires legislative ratification before implementation. 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, and the FPSC staff drafted a Florida RPS that would require that 20 percent of electricity produced in the state come from renewable resources by 2041. On January 12, 2009, the FPSC approved a draft Florida RPS rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida RPS rule to the Florida legislature in February 2009. The legislature will review, ratify as is, make revisions, or decide not to have a Florida RPS rule at all. We cannot predict the outcome of this matter.

We cannot 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. PEF has agreed that CR1 and CR2 will cease to be operated as coal-fired units by December 31, 2020. This date assumes timely licensing, construction and commencement of commercial operation of PEF's proposed new Levy Units 1 and 2. The retirement of CR1 and CR2 as coal-fired units is contingent upon completion of the first fuel cycle for Levy Unit 2. PEF shall advise the FDEP of any developments that would delay the retirement of CR1 and CR2 beyond the completion of the first fuel cycle for Levy Unit 2.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law includes provisions for NC REPS, 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 required PEC to submit its first annual NC REPS compliance plan as part of its integrated resource plan, which was filed on September 2, 2008. Under the new rules, beginning in 2009, PEC will also be required to file an annual NC REPS compliance report demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC 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 NC REPS clause will be set based on projected costs with true-up provisions. In 2008, PEC filed for NCUC approval of multiple DSM and energy-efficiency programs. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the DSM and energy-efficiency filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

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 22D.

INCREASING ENERGY DEMAND

Meeting the anticipated long-term 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 DSM, 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. 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. Our energy-efficiency program provides simple, low-cost options 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 producing electricity from swine waste and other plant or animal sources, solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from these and other 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. In 2007, PEC announced a two-year moratorium on constructing new coal-fired plants while pursuing expansion of energy-efficiency and conservation programs. If PEC proceeds with construction of a new nuclear plant, the new plant would not be online until at least 2019 (See "Nuclear" below).

As authorized under the 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. In June 2008, the DOE announced solicitations for a total of up to $30.5 billion of the amount authorized by Congress in federal loan guarantees for projects that employ advanced energy technologies that avoid, reduce or sequester air pollutants or greenhouse gas emissions and advanced nuclear facilities for the "front-end" of the nuclear fuel cycle.

PEF submitted Part I of the Application for Federal Loan Guarantees for Nuclear Power Facilities on September 29, 2008, for Levy. PEF was one of 19 applicants that submitted Part I of the application. Part II of the application was due on December 19, 2008. PEF decided not to pursue the loan guarantee program at this time. The program requires that the guarantee be in a first lien position on all assets of the project, which conflicts with PEF's current mortgage. Obtaining the required approval to amend the current mortgage from 100 percent of current bondholders would be unlikely, and current secured debt of $4.0 billion would need to be refinanced with unsecured debt to meet the requirements of the guarantee. In addition, the costs associated with obtaining the loan guarantee remain unclear at this time. However, this decision does not preclude PEF from revisiting the program at a later date if there are changes to the program. We cannot predict if PEF will pursue this program further.

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.

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. Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

On December 17, 2008, Harris received a 20-year extension from the NRC on its operating license, which extends the operating license through 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year extension from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida. 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 17, 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. On June 4, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene 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. One petition to intervene was filed with the NRC within the 60-day notice period. We cannot predict the outcome of this matter. 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 2019 (See "Increasing Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy 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. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors. The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. If we receive timely approval from the NRC and applicable state agencies, and if the decisions to build are made, safety-related construction activities could begin as early as 2012, and a new plant could be operational in the 2016 to 2018 timeframe (See "Increasing Energy Demand" above). On October 6, 2008, the NRC docketed, or accepted for review, the Levy nuclear project 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. On December 8, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene 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. One petition to intervene was filed with the NRC within the 60-day notice period. 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. On May 29, 2008, the Florida Department of Community Affairs (FDCA) issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

In addition, PEF filed its application for Site Certification with the FDEP on June 2, 2008. A decision on PEF's FDEP Site Certification Application is expected in 2009. On January 12, 2009, the FDEP filed a favorable staff analysis report in advance of site certification hearings set to commence on February 23, 2009.

In accordance with provisions of Florida's 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 site selection costs, preconstruction costs and the carrying cost on construction cost balance on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after 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. 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.

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 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for the Levy nuclear project, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the FPSC nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor. PEF will be a participant in the annual nuclear cost-recovery proceeding, which was opened by the FPSC on January 5, 2009. The proceeding will occur throughout the year with an order expected by the end of 2009.

PEF signed an EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The total cost for the two generating units is estimated to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion is estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The final cost of the project will depend on the completion dates, which will be determined in large part by the NRC review schedule. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. PEF is assessing the impact of the NRC schedule on the plans and estimated costs for Levy. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. In 2008, PEF made payments toward long-lead equipment and engineering related to the EPC agreement. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances.

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").

SPENT NUCLEAR FUEL MATTERS

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 (D.C. Court of Appeals) 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. On September 30, 2008, the EPA issued final rules for limiting radiation exposure at Yucca Mountain. The EPA retained the dose limit of 15 millirem per year for the first 10,000 years and established a dose limit of 100 millirem for annual exposure per year between 10,000 years and 1 million years. In February 2009, the NRC approved a final rule for the waste repository at Yucca Mountain incorporating these radiation protection standards. On October 10, 2008, the state of Nevada again filed suit with the D.C. Court of Appeals challenging the EPA standard.

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 the earliest date the repository may be able to start accepting spent nuclear fuel is 2020. The Utilities cannot predict the outcome of this matter.

The DOE submitted the license application for the proposed high-level nuclear waste repository at Yucca Mountain in June 2008. The NRC formally docketed the license application in September 2008, which begins the formal licensing phase that is anticipated to take three to four years. The state of Nevada and other interested parties are expected to intervene in the licensing proceedings.

On August 5, 2008, the DOE announced that its estimated cost to build and commence operations at the Yucca Mountain facility has increased from $57.5 billion to $96.2 billion due to an increase in material costs, an increase in the quantity of spent fuel to store and a refinement of the repository's design.

On October 9, 2008, the NRC proposed revisions to its waste confidence findings that would remove the provisions stating that the NRC's confidence in waste management, underlying the licensing of reactors, is based in part on a repository being in operation by 2025. Instead, the NRC states that repository capacity will be available within 50 to 60 years beyond the licensed operation of all reactors, and that used fuel generated in any reactor can be safely stored on site without significant environmental impact for at least 60 years beyond the licensed operation of the reactor.

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 (Robinson), Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated by 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 extended operating license.

See Note 22D for information about the complaint filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open the Yucca Mountain or other facility would leave the DOE open to further claims by utilities.

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.

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 potential and pending claims cannot be predicted. 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 likely would 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 installed pursuant to the provisions of CAIR, CAVR and mercury regulation, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 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, 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 change expenditures required by the Clean Smokestacks Act. Changes in projected fuel sources may require us to incur costs, which are not currently estimable, to install additional controls subsequent to 2013 in order to remain compliant with the requirements of the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the pollution control 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. See discussion regarding future recovery of costs to comply with 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).

Clean Air Interstate Rule

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set 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 participated in a coalition of Florida utilities that filed a challenge to the CAIR as it applied to Florida (PEF withdrew from the coalition during the fourth quarter of 2008). On July 11, 2008, the D.C. Court of Appeals issued its decision on multiple challenges to the CAIR, including the Florida challenge, which vacated the CAIR in its entirety. On September 24, 2008, petitions for rehearing were filed by several parties. On October 21, 2008, the D.C. Court of Appeals issued an order directing petitioners to address (1) whether any party is seeking to vacate the

CAIR, and (2) whether the court should stay its mandate until the EPA promulgates a revised rule. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The outcome of the additional proceedings cannot be predicted.

PEF is continuing construction of its in-process emission control projects. On December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units and complete construction of its emission control projects at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which is anticipated to be around 2020.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. At December 31, 2008, PEC had approximately $22 million in SO_2 emission allowances and an immaterial amount of NOx emission allowances. In order to achieve compliance with the requirements of the CAIR pursuant to its Integrated Clean Air Compliance Plan (discussed further in "Compliance Strategy"), PEF needed to purchase CAIR seasonal and annual NOx allowances. On November 12, 2008, the FPSC approved PEF's petition for recovery of its CAIR expenses, including NOx allowance inventory expense, through the ECRC. At December 31, 2008, PEF had approximately $59 million in annual NOx emission allowance inventory, $6 million in seasonal NOx emission allowance inventory and approximately $11 million in SO_2 emission allowance inventory. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements.

Clean Air Mercury Rule

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 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, which were denied on May 20, 2008. On September 17, 2008, the Utility Air Regulatory Group filed a petition for writ of certiorari with the U.S. Supreme Court with regard to the decision that vacated the CAMR. On October 17, 2008, the EPA filed a similar petition and subsequently withdrew it on January 29, 2009. The Utility Air Regulatory Group's petition for writ of certiorari was denied on February 23, 2009. The three states in which the Utilities operate adopted mercury regulations implementing the CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR and any review granted by the Supreme Court will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

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, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. 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 CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, on December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeal's December 23, 2008 decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for SO_2 and NOx. Depending on whether this determination continues to be maintained as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units. As a result, BART for SO_2 and NOx could apply specifically to PEC's and PEF's BART-eligible units. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, the FDEP has not determined the level of additional controls PEF may have to implement. The outcome of these matters cannot be predicted.

Compliance Strategy

Both PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with the requirements of the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and Clean Smokestacks Act resulted in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC.

PEC has completed installation of controls to meet the NOx SIP Call requirements. The NOx SIP Call is not applicable to sources in Florida. Expenditures for the NOx SIP Call included the cost to install NOx controls under programs by North Carolina and South Carolina to comply with the federal eight-hour ozone standard.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR through the ECRC (see discussion above regarding the vacating of the CAMR and remanding of the CAIR). 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 the Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with the 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 recommended compliance plan and associated contracts and recovery of costs for air pollution control projects. The estimated capital cost for the recommended plan was \$1.26 billion in the June 1, 2007 filing. 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. On April 2, 2008, PEF filed a petition for approval true-up of final 2007 environmental costs and a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the tables exclude AFUDC. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. Our estimated costs to comply with the CAVR prior to the July 11, 2008 D.C. Court of Appeals' decision regarding CAIR were approximately \$100 million at PEC. Our previous estimate of \$1.0 billion to comply with the CAVR at PEF related primarily to installation of control equipment at CR1 and CR2, which we subsequently have decided to retire as coal-fired units. 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, 2008
Clean Smokestacks Act	2002 – 2013	\$1,500 – 1,600	\$1,007
In-process CAIR projects(a)	2005 – 2010	1,200	847
CAVR(b)	– 2017	–	–
Mercury regulation(c)	2006 – 2017	–	5
Total air quality		2,700 – 2,800	1,859
Clean Water Act Section 316(b)(d)		–	–
Total air and water quality		\$2,700 – 2,800	\$1,859

PEC

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2008
Clean Smokestacks Act	2002 – 2013	\$1,500 – 1,600	\$1,007
In-process CAIR projects(a)	2005 – 2008	–	–
CAVR(b)	– 2017	–	–
Mercury regulation(c)	2006 – 2017	–	5
Total air quality		1,500 – 1,600	1,012
Clean Water Act Section 316(b)(d)		–	–
Total air and water quality		\$1,500 – 1,600	\$1,012

PEF

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2008
In-process CAIR projects(a)	2005 – 2010	\$1,200	\$847
CAVR(b)	– 2017	–	–
Mercury regulation(c)		–	–
Total air quality		1,200	847
Clean Water Act Section 316(b)(d)		–	–
Total air and water quality		\$1,200	\$847

(a) PEF is continuing construction of its in-process emission control projects. Additional compliance plans for PEC and PEF to meet the requirements of a revised rule will be determined upon finalization of the rule. See discussion under "Clean Air Interstate Rule."

(b) As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed. See discussion under "Clean Air Visibility Rule."

(c) Compliance plans to meet the requirements of a revised or new implementing rule will be determined upon finalization of the rule. See discussion under "Clean Air Mercury Rule."

(d) 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, Lee and Roxboro plants have been placed in service. The remaining first phase project at one of PEC's largest plants, Mayo, is under construction and is expected to be completed in 2009. 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. In 2008, PEC determined that its in-process CAIR project did not yield the desired compliance results and decided not to pursue completion of the project. Additional compliance projects requiring material environmental compliance costs may be implemented in the future

To date, expenditures at PEF for CAIR 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. As a result of changes in the scope of work related to estimation of costs for compliance with the CAIR and the uncertainty regarding the EPA's further CAIR proceedings, the delisting determination and the CAMR discussed above, PEF is currently unable to estimate certain costs of compliance. However, PEF believes that future costs to comply with new or subsequent rule interpretations could be significant. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when those new regulations are finalized.

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 was that compliance with the CAIR would 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 denial of the Section 126 petition; that appeal was held in abeyance pending resolution of the appeal of the CAIR then pending before the same court. On July 11, 2008, the D.C. Court of Appeals vacated the CAIR. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. On the basis of these developments, the appeal of EPA's denial of North Carolina's Section 126 petition was resumed and briefing on the merits has been completed. Oral argument is scheduled for March 12, 2009. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On September 20, 2006, the EPA announced changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter, including a new 24-hour standard for particulate matter less than 2.5 microns in diameter, which lowered the standard from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA decided not to establish a standard for particulate matter between 2.5 and 10 microns in diameter and eliminated the annual standard for particulate matter less than 10 microns in diameter, but retained the 24-hour standard for particulate matter less than 10 microns in diameter. These changes did not result in designation of any additional nonattainment areas in PEC's or PEF's service territories. 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, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. 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. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The outcome of this matter cannot be predicted.

On October 16, 2008, the EPA published a revision to the NAAQS for lead to 0.15 micrograms per cubic meter rolling three-month average. The former standard was 1.5 micrograms per cubic meter, calendar quarter average. The revision is not expected to have a material impact on our or the Utilities' results of operations or financial position.

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 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 included reported expenditures in excess of $1.0 billion for retrofit of pollution control equipment. 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.

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 will be generated at certain affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes is currently ongoing and will result in permitting, construction and treatment requirements imposed on the Utilities now and into the future. The future costs of these requirements could be material to our or the Utilities' results of operations or financial position.

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 permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. On December 2, 2008, the U.S. Supreme Court heard 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 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. Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other greenhouse gases. The Obama administration has agreed to review whether or not CO_2 emissions from coal-fired power plants should be regulated. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. While state-level study groups are active in all three of our jurisdictions, we continue to believe that this is an issue that requires a national policy framework – one that provides certainty and consistency. Our balanced solution is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation as discussed under "Other Matters – Increasing Energy Demand." In addition to a report issued in 2006, we issued an updated report on global climate change in the second quarter of 2008, which further evaluates and states our position on this dynamic issue. The outcome of this matter cannot be predicted.

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. As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate greenhouse gas emissions that would be presented to the legislature no earlier than January 2010.

On April 2, 2007, the U.S. Supreme Court 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. Court of Appeals against the EPA Administrator seeking an order requiring the EPA to make a determination within 60 days of whether greenhouse gas emissions endanger public health and welfare. The D.C. Court of Appeals denied the petition on June 26, 2008. On July 11, 2008, the EPA issued an Advance Notice of Proposed Rulemaking inviting public comment on the issues and options that should be considered in development of comprehensive greenhouse gas regulation under the Clean Air Act. Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review its earlier denials of waiver requests by states to regulate CO_2 emissions from vehicles. 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 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" 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, commercial paper and its revolving credit agreement 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.

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 2008 AS COMPARED TO 2007 AND 2007 AS COMPARED TO 2006

Cash Flows from Operations

In 2008, net cash provided by operating activities increased when compared to 2007. The $43 million increase in operating cash flow was primarily due to a $79 million increase in cash receipts from a wholesale customer due to the expiration of a prepayment agreement; income tax impacts including $80 million in lower income tax payments; a $57 million increase from accounts payable and payables to affiliates, largely driven by the timing of payments; a $45 million increase from timing of customer collections; and a $32 million increase from net interest payments. These impacts were partially offset by $119 million decrease in the recovery of fuel costs, largely driven by an under-recovery of fuels costs in 2008, and a $109 million increase in inventory purchases, primarily coal, driven by higher prices.

In 2007, net cash provided by operating activities decreased when compared to 2006. The $76 million decrease was primarily due to a $95 million decrease from accounts payable and payables to affiliates, a $73 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 $59 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 2006 of wholesale billings and the impact of weather.

Investing Activities

In 2008, net cash used by investing activities increased $150 million when compared with 2007. The increase was primarily due to a $79 million increase from changes in advances to affiliated companies and a $75 million decrease in net proceeds from 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.

In 2007, net 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.

Financing Activities

Net cash used by financing activities decreased $146 million for 2008 when compared to 2007. The decrease in net cash used by financing activities was primarily due to $322 million in net proceeds from the issuance of long-term debt in 2008, $143 million in dividends paid to the Parent in 2007, and outstanding commercial paper issuances of $110 million, offset by a $308 million change in advances from affiliated companies and a $100 million increase in the retirement of long-term debt.

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.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding money pool balance and for general corporate purposes.

On March 12, 2008, PEC amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEC's RCA is now scheduled to expire on June 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 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

On November 18, 2008, PEC; the Parent, as a well-known seasoned issuer; and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See "Credit Facilities and Registration Statements.")

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 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.")

In 2006, PEC did not issue or retire long-term debt.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2009, 2010 and 2011 are approximately $1.1 billion, $1.3 billion and $1.2 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and for environmental control facilities as discussed in Progress Energy "Capital Expenditures."

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 toward the end of the next decade. This approach will require PEC to make significant capital investments. See Progress Energy "Introduction – Strategy" for additional information. 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.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

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

	2008	2007
Common stock equity	**53.9%**	50.4%
Preferred stock	**0.8%**	0.8%
Total debt	**45.3%**	48.8%

See the discussion of PEC's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEC's debt and credit facilities.

~~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, 2008.

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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding PEC's contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs. The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2008, 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 11)	$ 3,516	$ –	$ 6	$ 900	$ 2,610
Interest payments on long-term debt (b)	2,214	183	364	311	1,356
Capital lease obligations (See Note 22B)	18	2	4	12	–
Operating leases (c) (See Note 22B)	758	37	36	48	637
Fuel and purchased power (d) (See Note 22A)	7,512	1,706	2,295	1,320	2,191
Other purchase obligations (See Note 22A)	297	189	94	8	6
Minimum pension funding requirements (e)	779	75	312	165	227
Other postretirement benefits (f) (See Note 16A)	243	17	40	47	139
Uncertain tax positions (g) (See Note 14)	–	–	–	–	–
Other commitments (h)	118	13	26	26	53
Total	$ 15,455	$ 2,222	$ 3,177	$ 2,837	$ 7,219

(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, 2008.

(c) Amounts include certain related executory cost commitments.

(d) 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 cost-recovery clauses in accordance with North Carolina and South Carolina regulations and therefore do not require separate liquidity support.

(e) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(f) Represents projected benefit payments for a total of 10 years related to PEC's postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

(g) Uncertain tax positions of $38 million are not reflected in this table as PEC 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 12-month period ending December 31, 2009.

(h) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $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" 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, commercial paper and its revolving credit agreement 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.

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 2008 AS COMPARED TO 2007 AND 2007 AS COMPARED TO 2006

Cash Flows from Operations

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $748 million decrease in operating cash flow was primarily due to a $331 million decrease in the recovery of fuel costs driven by the under-recovery of higher fuels costs in 2008; $323 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $47 million in net refunds of cash collateral in 2007; and a $87 million increase in inventory purchases, primarily driven by coal price increases and an increase in emission allowances purchases. See discussion of PEF's fuel cost recovery in Progress Energy "Future Liquidity and Capital Resources." The change in derivative collateral assets was primarily driven by the relative fair values of our commodity derivative instruments (See Note 17A).

Net 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 2007 compared to $47 million in net cash payments in 2006, 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 2006.

Investing Activities

In 2008, net cash used by investing activities increased $37 million when compared with 2007. The increase in cash used by investing activities was primarily due to a $338 million increase in capital expenditures for utility property additions, partially offset by a $298 million decrease from changes in advances to affiliated companies. The increase in capital expenditures for utility property additions was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow plant to more efficient natural gas-burning technology.

which will not be completed until 2009, and a $52 million decrease related to the Hines 4 facility, which was placed in service in 2007

In 2007, net 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, and nuclear projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility.

Financing Activities

Net cash provided by financing activities increased $781 million for 2008 when compared to 2007. The increase in cash provided by financing activities was primarily due to PEF's $1.475 billion in net proceeds from issuance of long-term debt and outstanding commercial paper issuances of $371 million in 2008, partially offset by $739 million in net proceeds from the issuance of $750 million of long-term debt in 2007 and a $443 million increase in long-term debt retirements.

Net cash provided by financing activities increased $956 million for 2007 when compared to 2006, primarily due to $739 million in net proceeds from the issuance of long-term debt in 2007 and dividends paid to the parent of $234 million in 2006.

On March 12, 2008, PEF amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEF's RCA is now scheduled to expire on March 28, 2011.

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 June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

On November 18, 2008, PEF; the Parent, as a well-known seasoned issuer; and PEC filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See "Credit Facilities and Registration Statements.")

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 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.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2009, 2010 and 2011 are approximately $1.4 billion to $1.7 billion, $1.3 billion to $1.5 billion, and $1.5 billion to $1.7 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and add environmental control facilities as discussed in Progress Energy "Capital Expenditures."

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 toward the end of the next decade. This approach will require PEF to make significant capital investments. See Progress Energy "Introduction – Strategy" for additional information. 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.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

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

	2008	2007
Common stock equity	**42.2%**	48.0%
Preferred stock	**0.4%**	0.5%
Total debt	**57.4%**	51.5%

See the discussion of PEF's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEF's debt and credit facilities.

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, 2008.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties (See Note 17). Both PEC and PEF also have limited counterparty exposure for commodity hedges (primarily gas and oil hedges) by spreading concentration risk over a number of partners.

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

As part of our debt portfolio management and daily cash management, we have variable rate long-term debt and typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 18 percent and 16 percent of consolidated debt had variable rates at December 31, 2008 and 2007, respectively.

Based on our variable rate long-term debt balances at December 31, 2008, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $11 million. Based on our short-term debt balances at December 31, 2008, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $11 million.

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, 2008 and 2007, 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 2009 to 2013 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, 2008 (dollars in millions)	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$ –	$ 306	$ 1,000	$ 950	$ 825	$ 6,265	$ 9,346	$ 9,909
Average interest rate	–	4.53%	6.96%	6.67%	4.96%	6.21%	6.17%	
Variable-rate long-term debt	–	$ 100	–	$ 100	–	$ 861	$ 1,061	$ 1,061
Average interest rate	–	5.20%	–	2.52%	–	1.90%	2.27%	
Debt to affiliated trust(a)	–	–	–	–	–	$ 309	$ 309	$ 290
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts(b)	$ 450	–	–	–	–	–	$ 450	$ (65)
Average pay rate	4.26%	–	–	–	–	–	4.26%	
Average receive rate	(c)	–	–	–	–	–	(c)	

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

(b) $250 million is for anticipated 10-year debt issue hedge maturing on March 1, 2019, and requires mandatory cash settlement on March 1, 2009. The remaining $200 million is for anticipated 10-year debt issue hedge maturing on April 1, 2019, and requires mandatory cash settlement on April 1, 2009.

(c) Rate is 3-month LIBOR, which was 1.425% at December 31, 2008.

During 2009, PEC terminated $250 million notional of anticipated 10-year debt issue hedges on January 12, 2009, in conjunction with PEC's issuance of $600 million 5.30% First Mortgage Bonds.

During January 2009, the Parent, PEC and PEF each entered into $50 million notional of anticipated 10-year debt issue hedges to mitigate exposure to interest rate risk in anticipation of future debt issuances.

During 2008, PEC terminated $100 million notional of anticipated 10-year debt issue hedges and $100 million notional of anticipated 30-year debt issue hedges on March 10, 2008, in conjunction with PEC's issuance of $325 million 6.30% First Mortgage Bonds.

During 2008, PEF entered into a series of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In January 2008, PEF entered into a $100 million notional 10-year forward starting swap and a $100 million notional 30-year forward starting swap. In May 2008, PEF entered into combined $100 million notional 10-year forward starting swaps and $150 million notional 30-year forward starting swaps. In June 2008, PEF entered into combined $100 million notional 30-year forward starting swaps. In June 2008, PEF terminated 10-year and 30-year debt issue hedges in conjunction with PEF's issuance of $500 million of 5.65% 10-year First Mortgage Bonds and $1.000 billion of 6.40% 30-year First Mortgage Bonds.

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 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 was for anticipated 10-year debt issue hedge maturing on April 1, 2018, and required mandatory cash settlement on April 1, 2008. The remaining $100 million was for anticipated 30-year debt issue hedge maturing on April 1, 2038, and required mandatory cash settlement on April 1, 2008.

(c) Rate was 3-month 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.

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, 2008 and 2007, the fair value of these funds was $1.089 billion and $1.384 billion, respectively, including $672 million and $804 million, respectively, for PEC and $417 million and $580 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, 2008 and 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million. A hypothetical 10 percent increase in the December 31, 2008 market price would result in a $3 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

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 physical commodity contracts are not derivatives 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, 2008, substantially all derivative commodity instrument positions were subject to retail regulatory treatment. 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.

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

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary, PVI, sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. 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 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 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 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 5). We had a $108 million cash collateral liability related to these contracts at December 31, 2007, included in other current liabilities on the Consolidated Balance Sheet. As discussed in Note 3A, 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.

Due to the divestitures of Gas and CCO, 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 in 2006. For the year ended December 31, 2006, discontinued operations, net of tax on the Consolidated Statements of Income included $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges, and immaterial net gains and losses from other derivative instruments related to Gas and CCO.

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. Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. 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. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2008 and 2007, PEC recorded a net realized gain of $2 million and a net realized loss of $9 million, respectively. PEC's net realized loss was not material during the year ended December 31, 2006. During the years ended December 31, 2008, 2007 and 2006, PEF recorded a net realized gain of $172 million, a net realized loss of $46 million and a net realized gain of $39 million, respectively.

At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in other liabilities and deferred credits on the PEC Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was 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 position included in derivative liabilities on the PEC Consolidated Balance Sheet. Certain counterparties have held cash collateral with PEC in support of these instruments. PEC had an $18 million cash collateral asset included in prepayments and other current assets on the PEC Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in current derivative assets, a $1 million long-term derivative asset position included in derivative assets, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as an $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 derivative liability position included in current derivative liabilities, and a $9 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. Certain counterparties have posted or held cash collateral in support of these instruments. PEF had a $335 million cash collateral asset included in derivative collateral posted and a $12 million cash collateral liability included in other current liabilities on the PEF Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding some of 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2008 and 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 2008, 2007 and 2006.

At December 31, 2008 and 2007, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

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 Progress Energy's Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEC.

INTEREST RATE RISK

The following tables provide information at December 31, 2008 and 2007, about PEC's interest rate risk sensitive instruments:

December 31, 2008 (dollars in millions)	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$ –	$ 6	$ –	$ 500	$ 400	$ 1,990	$ 2,896	$ 3,070
Average interest rate	–	6.30%	–	6.50%	5.13%	5.86%	5.87%	
Variable-rate long-term debt	–	–	–	–	–	$ 620	$ 620	$ 620
Average interest rate	–	–	–	–	–	2.01%	2.01%	
Interest rate forward contracts(a)	$ 250	–	–	–	–	–	$ 250	$ (35)
Average pay rate	4.18%	–	–	–	–	–	4.18%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) $250 million is for anticipated 10-year debt issue hedge maturing on March 1, 2018, and requires mandatory cash settlement on March 1, 2009.
(b) Rate is 3-month LIBOR, which was 1 425% at December 31, 2008.
During 2009, PEC terminated $250 million notional of anticipated 10-year debt issue hedges on January 12, 2009, in conjunction with PEC's issuance of $600 million of 5.30% First Mortgage Bonds.

During January 2009, PEC entered into a $50 million notional anticipated 10-year debt issue hedge to mitigate exposure to interest rate risk in anticipation of future debt issuance

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 was for anticipated 10-year debt issue hedge maturing on April 1, 2018, and required mandatory cash settlement on April 1, 2008 The remaining $100 million was for anticipated 30-year debt issue hedge maturing on April 1, 2038, and required mandatory cash settlement on April 1, 2008
(b) Rate was 3-month LIBOR, which was 4.70% at December 31, 2007.

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 Progress Energy's Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEF.

INTEREST RATE RISK

The following tables provide information at December 31, 2008 and 2007, about PEF's interest rate risk sensitive instruments:

December 31, 2008 (dollars in millions)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**	**Fair Value December 31, 2008**
Fixed-rate long-term debt	**$ –**	**$ 300**	**$ 300**	**$ –**	**$ 425**	**$ 2,925**	**$ 3,950**	**$ 4,305**
Average interest rate	**–**	**4.50%**	**6.65%**	**–**	**4.80%**	**6.06%**	**5.85%**	
Variable-rate long-term debt	**–**	**–**	**–**	**–**	**–**	**$ 241**	**$ 241**	**$ 241**
Average interest rate	**–**	**–**	**–**	**–**	**–**	**1.63%**	**1.63%**	

During 2008, PEF entered into a series of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In January 2008, PEF entered into a $100 million notional 10-year forward starting swap and a $100 million notional 30-year forward starting swap. In May 2008, PEF entered into combined $100 million notional 10-year forward starting swaps and $150 million notional 30-year forward starting swaps. In June 2008, PEF entered into combined $100 million notional 30-year forward starting swaps. In June 2008, PEF terminated 10-year and 30-year debt issue hedges in conjunction with PEF's issuance of $500 million of 5.65% 10-year First Mortgage Bonds and $1.000 billion of 6.40% 30-year First Mortgage Bonds.

During January 2009, PEF entered into a $50 million notional anticipated 10-year debt issue hedge to mitigate exposure to interest rate risk in anticipation of future debt issuance.

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%	

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.

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:

Combined Notes to the Financial Statements for Progress Energy, Inc., Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. and Florida Power Corporation d/b/a Progress Energy Florida, Inc.

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, 4 through 9, 11 through 14, 16 through 22 and 24
PEF	1, 2, 4 through 9, 11 through 14, 16 through 22 and 24

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, 2008 and 2007, 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, 2008. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, 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.

As discussed in Notes 2, 14 and 16 to the consolidated financial statements, on January 1, 2008 the Company adopted Financial Accounting Standards Board Staff Position No. FIN 39-1, 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, 2008, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 2, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data) Years ended December 31	2008	2007	2006
Operating revenues	$ 9,167	$ 9,153	$ 8,724
Operating expenses			
Fuel used in electric generation	3,021	3,145	3,008
Purchased power	1,299	1,184	1,100
Operation and maintenance	1,820	1,842	1,583
Depreciation, amortization and accretion	839	905	1,011
Taxes other than on income	508	501	500
Other	(3)	30	35
Total operating expenses	7,484	7,607	7,237
Operating income	1,683	1,546	1,487
Other income (expense)			
Interest income	24	34	59
Allowance for equity funds used during construction	122	51	21
Other, net	(17)	(7)	(37)
Total other income, net	129	78	43
Interest charges			
Interest charges	679	605	631
Allowance for borrowed funds used during construction	(40)	(17)	(7)
Total interest charges, net	639	588	624
Income from continuing operations before income tax and minority interest	1,173	1,036	906
Income tax expense	395	334	339
Minority interest in subsidiaries' income, net of tax	(5)	(9)	(16)
Income from continuing operations	773	693	551
Discontinued operations, net of tax	57	(189)	20
Net income	$ 830	$ 504	$ 571
Average common shares outstanding – basic	260	256	250
Basic earnings per common share			
Income from continuing operations	$ 2.97	$ 2.71	$ 2.20
Discontinued operations, net of tax	0.22	(0.74)	0.08
Net income	$ 3.19	$ 1.97	$ 2.28
Diluted earnings per common share			
Income from continuing operations	$ 2.96	$ 2.70	$ 2.20
Discontinued operations, net of tax	0.22	(0.74)	0.08
Net income	$ 3.18	$ 1.96	$ 2.28
Dividends declared per common share	$ 2.465	$ 2.445	$ 2.425

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

PROGRESS ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2008	2007
ASSETS		
Utility plant		
Utility plant in service	$ 26,326	$ 25,327
Accumulated depreciation	(11,298)	(10,895)
Utility plant in service, net	15,028	14,432
Held for future use	38	37
Construction work in progress	2,745	1,765
Nuclear fuel, net of amortization	482	371
Total utility plant, net	18,293	16,605
Current assets		
Cash and cash equivalents	180	255
Receivables, net	867	1,122
Inventory	1,239	994
Regulatory assets	533	154
Derivative collateral posted	353	–
Income taxes receivable	194	24
Assets to be divested	–	52
Prepayments and other current assets	154	201
Total current assets	3,520	2,802
Deferred debits and other assets		
Regulatory assets	2,567	946
Nuclear decommissioning trust funds	1,089	1,384
Miscellaneous other property and investments	446	448
Goodwill	3,655	3,655
Derivative assets	1	119
Other assets and deferred debits	302	379
Total deferred debits and other assets	8,060	6,931
Total assets	$ 29,873	$ 26,338
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 264 million and 260 million shares issued and outstanding, respectively	$ 6,206	$ 6,028
Unearned ESOP shares (1 million and 2 million shares, respectively)	(25)	(37)
Accumulated other comprehensive loss	(116)	(34)
Retained earnings	2,622	2,438
Total common stock equity	8,687	8,395
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93
Minority interest	6	84
Long-term debt, affiliate	272	271
Long-term debt, net	10,387	8,466
Total capitalization	19,445	17,309
Current liabilities		
Current portion of long-term debt	–	877
Short-term debt	1,050	201
Accounts payable	912	819
Interest accrued	167	173
Dividends declared	164	160
Customer deposits	282	255
Regulatory liabilities	6	173
Derivative liabilities	493	57
Liabilities to be divested	–	8
Other current liabilities	412	579
Total current liabilities	3,486	3,302
Deferred credits and other liabilities		
Noncurrent income tax liabilities	818	361
Accumulated deferred investment tax credits	127	139
Regulatory liabilities	2,181	2,554
Asset retirement obligations	1,471	1,378
Accrued pension and other benefits	1,594	763
Capital lease obligations	231	239
Derivative liabilities	269	17
Other liabilities and deferred credits	251	276
Total deferred credits and other liabilities	6,942	5,727
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$ 29,873	$ 26,338

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2008	2007	2006
Operating activities			
Net income	$ 830	$ 504	$ 571
Adjustments to reconcile net income to net cash provided by operating activities			
Impairment of assets	–	–	174
Depreciation, amortization and accretion	957	1,026	1,190
Deferred income taxes and investment tax credits, net	411	177	(251)
Deferred fuel (credit) cost	(333)	117	396
Deferred income	–	(128)	(69)
Allowance for equity funds used during construction	(122)	(51)	(21)
Other adjustments to net income	66	175	109
Cash provided (used) by changes in operating assets and liabilities			
Receivables	233	(186)	59
Inventory	(237)	(11)	(168)
Derivative collateral posted	(340)	55	(52)
Prepayments and other current assets	7	35	(81)
Income taxes, net	(169)	(275)	197
Accounts payable	77	(40)	34
Other current liabilities	(103)	81	10
Other assets and deferred debits	(44)	(198)	(70)
Other liabilities and deferred credits	(15)	(29)	(27)
Net cash provided by operating activities	1,218	1,252	2,001
Investing activities			
Gross property additions	(2,333)	(1,973)	(1,572)
Nuclear fuel additions	(222)	(228)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	72	675	1,657
Purchases of available-for-sale securities and other investments	(1,590)	(1,413)	(2,452)
Proceeds from available-for-sale securities and other investments	1,534	1,452	2,631
Other investing activities	(2)	30	(23)
Net cash (used) provided by investing activities	(2,541)	(1,457)	127
Financing activities			
Issuance of common stock	132	151	185
Dividends paid on common stock	(642)	(627)	(607)
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	176	–
Net increase (decrease) in short-term debt	1,096	25	(175)
Proceeds from issuance of long-term debt, net	1,797	739	397
Retirement of long-term debt	(877)	(324)	(2,200)
Cash distributions to minority interests of consolidated subsidiaries	(85)	(10)	(79)
Other financing activities	(26)	65	11
Net cash provided (used) by financing activities	1,248	195	(2,468)
Net decrease in cash and cash equivalents	(75)	(10)	(340)
Cash and cash equivalents at beginning of year	255	265	605
Cash and cash equivalents at end of year	$ 180	$ 255	$ 265
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	$ 612	$ 585	$ 698
Income taxes, net of refunds	152	176	311
Significant noncash transactions			
Capital lease obligation incurred	–	182	54
Note receivable for disposal of ownership interest in Ceredo	–	48	–
Accrued property additions	334	329	231

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except per share data)	Stock Outstanding Shares	Common Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2005, as restated (See Note 1B)	**252**	**$ 5,571**	**$ (63)**	**$ (104)**	**$ 2,607**	**$ 8,011**
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 ($2.425 per share)		–	–	–	(611)	(611)
Balance, December 31, 2006, as restated (See Note 1B)	**256**	**5,791**	**(50)**	**(49)**	**2,567**	**8,259**
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 ($2.445 per share)		–	–	–	(631)	(631)
Balance, December 31, 2007, as restated (See Note 1B)	**260**	**6,028**	**(37)**	**(34)**	**2,438**	**8,395**
Net income		**–**	**–**	**–**	**830**	**830**
Other comprehensive loss		**–**	**–**	**(82)**	**–**	**(82)**
Comprehensive income						**748**
Issuance of shares	**4**	**131**	**–**	**–**	**–**	**131**
Stock options exercised		**1**	**–**	**–**	**–**	**1**
Allocation of ESOP shares		**13**	**12**	**–**	**–**	**25**
Stock-based compensation expense		**33**	**–**	**–**	**–**	**33**
Dividends ($2.465 per share)		**–**	**–**	**–**	**(646)**	**(646)**

Balance, December 31, 2008	264	$	6,206	$	(25)	$	(116)	$	2,622	$ 8,687

See Notes to Progress Energy, Inc Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	2008	2007	2006
Net income	**$830**	$504	$ 571
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax (expense) benefit of $(2), $(3) and $28, respectively)	**3**	4	(46)
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $1 and $1, respectively)	**1**	2	–
Net unrealized losses on cash flow hedges (net of tax benefit of $24, $8 and $16, respectively)	**(37)**	(13)	(23)
Net unrecognized items on pension and other postretirement benefits (net of tax benefit (expense) of $29 and $(16), respectively)	**(49)**	23	–
Minimum pension liability adjustment (net of tax expense of $30)	**–**	–	48
Other (net of tax benefit of $1, $3 and $-, respectively)	**–**	(1)	3
Other comprehensive (loss) income	**(82)**	15	(18)
Comprehensive income	**$748**	$519	$ 553

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, 2008 and 2007, 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, 2008. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, 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.

As discussed in Notes 2, 14 and 16 to the consolidated financial statements, on January 1, 2008 the Company adopted Financial Accounting Standards Board Staff Position No. FIN 39-1, 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.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

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

(in millions) Years ended December 31	2008	2007	2006
Operating revenues	$ 4,429	$ 4,385	$ 4,086
Operating expenses			
Fuel used in electric generation	1,346	1,381	1,173
Purchased power	346	302	334
Operation and maintenance	1,030	1,024	930
Depreciation, amortization and accretion	518	519	571
Taxes other than on income	198	192	191
Other	(5)	(2)	–
Total operating expenses	3,433	3,416	3,199
Operating income	996	969	887
Other income			
Interest income	12	21	25
Allowance for equity funds used during construction	27	10	4
Other, net	4	6	21
Total other income, net	43	37	50
Interest charges			
Interest charges	219	215	217
Allowance for borrowed funds used during construction	(12)	(5)	(2)
Total interest charges, net	207	210	215
Income before income tax	832	796	722
Income tax expense	298	295	265
Net income	534	501	457
Preferred stock dividend requirement	3	3	3
Net income available to common stockholders	$ 531	$ 498	$ 454

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	2008	2007
ASSETS		
Utility plant		
Utility plant in service	**$15,698**	$15,117
Accumulated depreciation	**(7,352)**	(7,097)
Utility plant in service, net	**8,346**	8,020
Held for future use	**3**	2
Construction work in progress	**660**	566
Nuclear fuel, net of amortization	**376**	292
Total utility plant, net	**9,385**	8,880
Current assets		
Cash and cash equivalents	**18**	25
Receivables, net	**502**	446
Receivables from affiliated companies	**29**	42
Notes receivable from affiliated companies	**55**	–
Inventory	**633**	510
Deferred fuel cost	**207**	148
Income taxes receivable	**98**	8
Prepayments and other current assets	**28**	60
Total current assets	**1,570**	1,239
Deferred debits and other assets		
Regulatory assets	**1,243**	680
Nuclear decommissioning trust funds	**672**	804
Miscellaneous other property and investments	**197**	192
Other assets and deferred debits	**98**	160
Total deferred debits and other assets	**2,210**	1,836
Total assets	**$13,165**	$11,955
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	**$ 2,083**	$ 2,054
Unearned ESOP common stock	**(25)**	(37)
Accumulated other comprehensive loss	**(35)**	(10)
Retained earnings	**2,278**	1,745
Total common stock equity	**4,301**	3,752
Preferred stock – not subject to mandatory redemption	**59**	59
Long-term debt, net	**3,509**	3,183
Total capitalization	**7,869**	6,994
Current liabilities		
Current portion of long-term debt	**–**	300
Short-term debt	**110**	–
Notes payable to affiliated companies	**–**	154
Accounts payable	**377**	308
Payables to affiliated companies	**82**	71
Interest accrued	**59**	58
Customer deposits	**82**	70
Derivative liabilities	**82**	19
Other current liabilities	**173**	190
Total current liabilities	**965**	1,170
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**1,111**	936
Accumulated deferred investment tax credits	**115**	122
Regulatory liabilities	**987**	1,098
Asset retirement obligations	**1,122**	1,063
Accrued pension and other benefits	**856**	459
Other liabilities and deferred credits	**140**	113
Total deferred credits and other liabilities	**4,331**	3,791
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$13,165**	$11,955

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	**2008**	2007	2006
Operating activities			
Net income	**$ 534**	$ 501	$ 457
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**616**	608	656
Deferred income taxes and investment tax credits, net	**204**	41	(59)
Deferred fuel (credit) cost	**(71)**	48	(8)
Allowance for equity funds used during construction	**(27)**	(10)	(4)
Other adjustments to net income	**45**	(37)	(19)
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(61)**	(16)	33
Receivables from affiliated companies	**13**	(15)	9
Inventory	**(119)**	(10)	(69)
Prepayments and other current assets	**4**	(17)	10
Income taxes, net	**(116)**	(37)	(24)
Accounts payable	**42**	33	59
Payables to affiliated companies	**11**	(37)	32
Other current liabilities	**34**	(29)	(16)
Other assets and deferred debits	**7**	(28)	38
Other liabilities and deferred credits	**(55)**	23	(1)
Net cash provided by operating activities	**1,061**	1,018	1,094
Investing activities			
Gross property additions	**(760)**	(757)	(705)
Nuclear fuel additions	**(179)**	(184)	(102)
Purchases of available-for-sale securities and other investments	**(682)**	(603)	(896)
Proceeds from available-for-sale securities and other investments	**626**	622	1,006
Changes in advances to affiliated companies	**(55)**	24	(24)
Other investing activities	**8**	6	(1)
Net cash used by investing activities	**(1,042)**	(892)	(722)
Financing activities			
Dividends paid on preferred stock	**(3)**	(3)	(3)
Dividends paid to parent	**–**	(143)	(339)
Net increase (decrease) in short-term debt	**110**	–	(73)
Proceeds from issuance of long-term debt, net	**322**	–	–
Retirement of long-term debt	**(300)**	(200)	–
Changes in advances from affiliated companies	**(154)**	154	(11)
Contributions from parent	**15**	21	–
Other financing activities	**(16)**	(1)	–
Net cash used by financing activities	**(26)**	(172)	(426)
Net decrease in cash and cash equivalents	**(7)**	(46)	(54)
Cash and cash equivalents at beginning of year	**25**	71	125
Cash and cash equivalents at end of year	**$ 18**	$ 25	$ 71
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	**$ 193**	$ 210	$ 210
Income taxes, net of refunds	**211**	291	347
Significant noncash transactions			
Accrued property additions	**99**	87	104

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	Common Stock Outstanding Amount	Unearned ESOP Common Stock	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2005, as restated (See Note 1B)	**160**	**$ 1,981**	**$ (63)**	**$ (120)**	**$ 1,293**	**$ 3,091**
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, as restated (See Note 1B)	**160**	**2,010**	**(50)**	**(1)**	**1,404**	**3,363**
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, as restated (See Note 1B)	**160**	**2,054**	**(37)**	**(10)**	**1,745**	**3,752**
Net income		**–**	**–**	**–**	**534**	**534**
Other comprehensive loss		**–**	**–**	**(25)**	**–**	**(25)**
Comprehensive income						**509**
Stock-based compensation expense		**13**	**–**	**–**	**–**	**13**
Allocation of ESOP shares		**16**	**12**	**–**	**–**	**28**
Preferred stock dividends at stated rates		**–**	**–**	**–**	**(3)**	**(3)**
Tax benefit dividend		**–**	**–**	**–**	**2**	**2**
Balance, December 31, 2008	**160**	**$ 2,083**	**$ (25)**	**$ (35)**	**$ 2,278**	**$ 4,301**

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

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2008**	2007	2006
Net income	**$534**	$501	$ 457
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $1)	**1**	–	–
Net unrealized losses on cash flow hedges (net of tax benefit of $17, $4 and $2, respectively)	**(26)**	(5)	(2)
Minimum pension liability adjustment (net of tax expense of $23)	–	–	36
Other (net of tax benefit of $-, $1 and $1, respectively)	–	(4)	2
Other comprehensive (loss) income	**(25)**	(9)	36
Comprehensive income	**$509**	$492	$ 493

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, 2008 and 2007, 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, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, 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.

As discussed in Notes 2, 14 and 16 to the financial statements, on January 1, 2008 the Company adopted Financial Accounting Standards Board Staff Position No. FIN 39-1, 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.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

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

(in millions) Years ended December 31	2008	2007	2006
Operating revenues	**$4,731**	$4,749	$4,639
Operating expenses			
Fuel used in electric generation	**1,675**	1,764	1,835
Purchased power	**953**	882	766
Operation and maintenance	**813**	834	684
Depreciation, amortization and accretion	**306**	366	404
Taxes other than on income	**309**	309	309
Other	**(5)**	8	(2)
Total operating expenses	**4,051**	4,163	3,996
Operating income	**680**	586	643
Other income (expense)			
Interest income	**9**	9	15
Allowance for equity funds used during construction	**95**	41	17
Other, net	**(10)**	(2)	(4)
Total other income, net	**94**	48	28
Interest charges			
Interest charges	**236**	185	155
Allowance for borrowed funds used during construction	**(28)**	(12)	(5)
Total interest charges, net	**208**	173	150
Income before income tax	**566**	461	521
Income tax expense	**181**	144	193
Net income	**385**	317	328
Preferred stock dividend requirement	**2**	2	2
Net income available to common stockholders	**$ 383**	$ 315	$ 326

See Notes to PEF Financial Statements.

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

BALANCE SHEETS

(in millions) December 31	2008	2007
ASSETS		
Utility plant		
Utility plant in service	**$10,449**	$10,025
Accumulated depreciation	**(3,885)**	(3,738)
Utility plant in service, net	**6,564**	6,287
Held for future use	**35**	35
Construction work in progress	**2,085**	1,199
Nuclear fuel, net of amortization	**106**	79
Total utility plant, net	**8,790**	7,600
Current assets		
Cash and cash equivalents	**19**	23
Receivables, net	**362**	351
Receivables from affiliated companies	**15**	8
Notes receivable from affiliated companies	**–**	149
Inventory	**606**	484
Regulatory assets	**326**	6
Derivative assets	**9**	83
Derivative collateral posted	**335**	–
Prepayments and other current assets	**130**	83
Total current assets	**1,802**	1,187
Deferred debits and other assets		
Regulatory assets	**1,324**	266
Nuclear decommissioning trust funds	**417**	580
Miscellaneous other property and investments	**37**	46
Derivative assets	**1**	100
Prepaid pension cost	**–**	221
Other assets and deferred debits	**100**	63
Total deferred debits and other assets	**1,879**	1,276
Total assets	**$12,471**	$10,063
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$ 1,116**	$ 1,109
Accumulated other comprehensive loss	**(1)**	(8)
Retained earnings	**2,284**	1,901
Total common stock equity	**3,399**	3,002
Preferred stock – not subject to mandatory redemption	**34**	34
Long-term debt, net	**4,182**	2,686
Total capitalization	**7,615**	5,722
Current liabilities		
Current portion of long-term debt	**–**	532
Short-term debt	**371**	–
Notes payable to affiliated companies	**72**	–
Accounts payable	**514**	473
Payables to affiliated companies	**55**	87
Interest accrued	**51**	57
Customer deposits	**200**	185
Regulatory liabilities	**6**	173
Derivative liabilities	**380**	38
Other current liabilities	**122**	92
Total current liabilities	**1,771**	1,637
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**634**	401
Accumulated deferred investment tax credits	**12**	17
Regulatory liabilities	**1,076**	1,330
Asset retirement obligations	**349**	315
Accrued pension and other benefits	**494**	304
Capital lease obligations	**216**	224
Derivative liabilities	**209**	9
Other liabilities and deferred credits	**95**	104
Total deferred credits and other liabilities	**3,085**	2,704
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$12,471**	$10,063

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	**2008**	2007	2006
Operating activities			
Net income	$ **385**	$ 317	$ 328
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**320**	385	433
Deferred income taxes and investment tax credits, net	**130**	(44)	(48)
Deferred fuel (credit) cost	**(262)**	69	404
Allowance for equity funds used during construction	**(95)**	(41)	(17)
Other adjustments to net income	**40**	77	36
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(26)**	(8)	(39)
Receivables from affiliated companies	**(7)**	3	–
Inventory	**(122)**	(35)	(128)
Derivative collateral posted	**(323)**	47	(47)
Prepayments and other current assets	**(15)**	25	10
Income taxes, net	**–**	3	(56)
Accounts payable	**48**	43	19
Payables to affiliated companies	**(32)**	(29)	15
Other current liabilities	**(10)**	35	20
Other assets and deferred debits	**(8)**	(44)	13
Other liabilities and deferred credits	**28**	(4)	(50)
Net cash provided by operating activities	**51**	799	893
Investing activities			
Gross property additions	**(1,552)**	(1,214)	(727)
Nuclear fuel additions	**(43)**	(44)	(12)
Purchases of available-for-sale securities and other investments	**(782)**	(640)	(625)
Proceeds from available-for-sale securities and other investments	**784**	640	625
Changes in advances to affiliated companies	**149**	(149)	–
Proceeds from sales of assets to affiliated companies	**12**	–	–
Other investing activities	**(7)**	5	4
Net cash used by investing activities	**(1,439)**	(1,402)	(735)
Financing activities			
Dividends paid on preferred stock	**(2)**	(2)	(2)
Dividends paid to parent	**–**	–	(234)
Net increase (decrease) in short-term debt	**371**	–	(102)
Proceeds from issuance of long-term debt, net	**1,475**	739	–
Retirement of long-term debt	**(532)**	(89)	(48)
Changes in advances from affiliated companies	**72**	(47)	34
Other financing activities	**–**	2	(1)
Net cash provided (used) by financing activities	**1,384**	603	(353)
Net decrease in cash and cash equivalents	**(4)**	–	(195)
Cash and cash equivalents at beginning of year	**23**	23	218
Cash and cash equivalents at end of year	$ **19**	$ 23	$ 23
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	$ **205**	$ 149	$ 152
Income taxes, net of refunds	**52**	184	296
Significant noncash transactions			
Capital lease obligation incurred	**–**	182	54
Accrued property additions	**231**	238	119

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 Outstanding Amount		Accumulated Other Comprehensive Loss		Retained Earnings		Total Common Stock Equity
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**
Net income			**–**		**–**		**385**		**385**
Other comprehensive income			**–**		**7**		**–**		**7**
Comprehensive income									**392**
Stock-based compensation expense			**7**		**–**		**–**		**7**
Preferred stock dividends at stated rates			**–**		**–**		**(2)**		**(2)**
Balance, December 31, 2008	**100**	**$**	**1,116**	**$**	**(1)**	**$**	**2,284**	**$**	**3,399**

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

(in millions) Years ended December 31	**2008**	2007	2006
Net income	**$385**	$317	$328
Other comprehensive income (loss)			
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(5), $5 and $1, respectively)	7	(7)	(1)
Other comprehensive income (loss)	7	(7)	(1)
Comprehensive income	$392	$310	$327

See Notes to PEF Financial Statements

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

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

PROGRESS ENERGY, INC.

The Parent is a holding company headquartered in Raleigh, N.C. 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, 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 12 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.

Our 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."

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 2007 and 2006 have been reclassified to conform to the 2008 presentation.

RESTATEMENT

During the preparation of our December 31, 2008 financial statements, we identified an error in accounting for our and PEC's unbilled revenue. The cumulative impact of this error on beginning retained earnings and common stock equity at December 31, 2005, was a decrease of $27 million.

PROGRESS ENERGY

The following table reflects the effects of the restatement on the Consolidated Statements of Changes in Common Stock Equity as of December 31, 2006:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Retained earnings	$ 2,594	$ (27)	$ 2,567
Total common stock equity	8,286	(27)	8,259

The following table reflects the effects of the restatement on the Consolidated Balance Sheet and Consolidated Statement of Changes in Common Stock Equity as of December 31, 2007:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Receivables, net	$ 1,167	$ (45)	$ 1,122
Prepayments and other current assets	183	18	201
Total current assets	2,829	(27)	2,802
Total assets	26,365	(27)	26,338
Retained earnings	2,465	(27)	2,438
Total common stock equity	8,422	(27)	8,395
Total capitalization	17,336	(27)	17,309
Total capitalization and liabilities	26,365	(27)	26,338

Our net income for the years ended December 31, 2008, 2007 and 2006 was not materially impacted by this error; accordingly no income adjustments have been recorded.

PEC

The following table reflects the effects of the restatement on the PEC Consolidated Statements of Changes in Common Stock Equity as of December 31, 2006:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Retained earnings	$ 1,431	$ (27)	$ 1,404
Total common stock equity	3,390	(27)	3,363

The following table reflects the effects of the restatement on the PEC Consolidated Balance Sheet and Consolidated Statement of Changes in Common Stock Equity as of December 31, 2007:

(in millions)	As Previously Reported	Restatement Adjustments	As Restated
Receivables, net	$ 491	$ (45)	$ 446
Prepayments and other current assets	42	18	60
Total current assets	1,266	(27)	1,239
Total assets	11,982	(27)	11,955
Retained earnings	1,772	(27)	1,745
Total common stock equity	3,779	(27)	3,752
Total capitalization	7,021	(27)	6,994
Total capitalization and liabilities	11,982	(27)	11,955

PEC's net income for the years ended December 31, 2008, 2007 and 2006 was not materially impacted by this error; accordingly no income adjustments have been recorded.

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 (VIEs) 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).

In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk which identifies which variable interest holder absorbs the majority of the financial risk and variability of the VIE. In performing this analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity. If the qualitative analysis is inconclusive, a specific quantitative analysis is performed in accordance with FIN 46R.

In December 2008, the FASB issued FASB Staff Position (FSP) No. FAS 140-4 and FIN 46R-8, "Disclosures by Public Entities (Enterprises) About Transfers of Financial Assets and Interests in Variable Interest Entities," which is effective for Progress Energy on December 31, 2008. This FSP amended the disclosure requirements of FIN 46R. The Progress Registrants' disclosures required by the FSP are presented below. For purposes of these disclosures, the maximum loss amounts represent the maximum exposure that would be absorbed by the Progress Registrants in the event that all of the assets of the VIE are deemed worthless, including any additional costs that the Progress Registrants would incur.

PROGRESS ENERGY

In addition to the variable interests listed below for PEC and PEF, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2007 or 2008. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2008, we had no assets and $20 million of liabilities related to the legal and tax indemnifications provided to the buyer included in other liabilities and deferred credits in the Progress Energy Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the loss on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 3J for additional information on the disposal of Ceredo and Note 22C for a general discussion of guarantees.

PEC

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

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. PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2008, PEC had assets of $40 million, substantially all of which was reflected in miscellaneous other property and investment, and $16 million in long-term debt, $7 million in other liabilities and deferred credits and $4 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase 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 $44 million, $39 million and $45 million in 2008, 2007 and 2006, 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 investment fund's 17 partnerships and the power plant owner are VIEs 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 power plant and the investment fund consolidating the 17 partnerships 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.

PEF

The following information is provided for PEF's significant variable interests in VIEs for which PEF is not the primary beneficiary:

PEF has a prepayment clause in a building capital lease with a special purpose entity that is a VIE. In accordance with the lease agreement, PEF is not required to make any lease payments over the last 20 years of the lease, during which period $51 million of rental expense will be recorded in the PEF Statements of Income. The prepayment clause is PEF's only variable interest in the VIE and, therefore, PEF's exposure to loss primarily relates to the recovery of the prepayments through future use of the rental property. PEF performed qualitative and quantitative analyses and concluded that it is not the primary beneficiary of the VIE. The primary factors in the analyses were the lease term, the fact that the lease payments are not variable interests, the likelihood of construction and casualty risks to the building and the existence of insurance to offset those risks, and the estimated fair value of the building at the end of the lease term. There were no changes to PEF's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIE during the periods presented. At December 31, 2008, PEF had a $4 million prepayment included in prepayments and other current assets on the PEF Balance Sheets. No liabilities associated with the prepayment clause were recorded. The aggregate maximum exposure to loss at December 31, 2008, is $51 million, which represents the loss if the maximum prepayment of rent at the end of year 20 was not recovered through future use of the rental property or from third-party insurers at that time.

PEF has a residual value guarantee in an operating railcar lease agreement with a special purpose entity that is a VIE. The lease agreement has an early termination clause that permits PEF to terminate the lease in certain circumstances. If PEF terminates the lease in accordance with the agreement, it must sell the railcars and remit the proceeds to the lessor plus any amount for which the residual value guarantee exceeds the realized value of the equipment. The residual value guarantee is PEF's primary variable interest in the VIE and, therefore, PEF's exposure to loss is from the potential decrease in the fair value of the railcars. PEF performed qualitative and quantitative analyses and concluded that it is not the primary beneficiary of the VIE. The primary factors in the analyses were the terms of the lease, the probability of exercising the early termination clause, and the estimated fair value of the railcars. There were no changes to PEF's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIE during the periods presented. No liabilities associated with the residual value guarantee were recorded as of December 31, 2008, because the early termination clause was not exercised. The aggregate maximum exposure to loss at December 31, 2008, is $18 million, which represents the maximum loss if the early termination clause were exercised in 2009 and the related railcars were deemed worthless.

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 base revenues earned when service has been delivered but not billed by the end of the accounting period. 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)	2008	2007	2006
Progress Energy	$ **295**	$ 299	$ 293
PEC	**102**	99	94
PEF	**193**	200	199

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R).

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 (AROs) 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.

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 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates 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 and froze North Carolina electric utility base rates for a five-year period, which ended in 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. In September 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks compliance costs (See Note 7B).

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 the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income. The adoption of SFAS No. 143 and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143" (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.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with an original 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.

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.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through PEF's fuel cost-recovery clause. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

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. Income taxes are provided for as if PEC and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax 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 in the Consolidated Statements of Income.

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," 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 on 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. In accordance with FSP No. FIN 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts," (FSP FIN 39-1), we elect not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. 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. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. 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. 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

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.

2. NEW ACCOUNTING STANDARDS

Refer to Note 1C for information regarding our implementation of FIN 46R-8, "Disclosures by Public Entities (Enterprises) About Transfers of Financial Assets and Interests in Variable Interest Entities," which is effective for Progress Energy on December 31, 2008, and which amended the disclosure requirements of FIN 46R.

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

On January 1, 2008, we implemented FSP FIN 39-1, which allows a reporting entity to make an accounting election whether or not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Prior to the adoption of FSP FIN 39-1, we and the Utilities offset fair value amounts recognized for derivative instruments under master netting arrangements. FSP FIN 39-1 was implemented as a retrospective change in accounting principle and upon adoption, Progress Energy, PEC and PEF discontinued the offset of fair value amounts for such derivatives. The adoption of FSP FIN 39-1 did not have a material impact on our or the Utilities' financial position or results of operations.

Fair Value Measurements - Adoption of FASB Statements Nos. 157 and 159

Refer to Note 13B for information regarding our first quarter 2008 implementation of 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.

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 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.

SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133"

In March 2008, the FASB issued SFAS Statement 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 Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for us on January 1, 2009, and encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The adoption of SFAS No. 161 will change certain disclosures in the notes to the financial statements, but will have no impact on our or the Utilities' financial position or results of operations.

FSP No. SFAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets"

In December 2008, the FASB issued FSP No. SFAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets" (FSP SFAS 132R-1), which requires additional disclosures on the investment allocation decision making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. FSP SFAS 132R-1 is effective for us on December 31, 2009. The adoption of FSP SFAS 132R-1 will change certain disclosures in the notes to the financial statements, 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 coal terminals had 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. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements 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 Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

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 was reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented 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 were located.

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, 2007 and 2006 was $1 million. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during the years ended December 31, 2007 and 2006 was $2 million and $4 million, respectively.

Results of Terminals and the synthetic fuels businesses discontinued operations for the years ended December 31 were as follows:

(in millions)	2008	2007	2006
Revenues	$ 17	$ 1,126	$ 847
Earnings (loss) before income taxes and minority interest	$ 8	$ 2	$ (179)
Income tax benefit, including tax credits	12	64	135
Minority interest share of (earnings) losses	(1)	17	7
Net earnings (loss) from discontinued operations	19	83	(37)
Gain on disposal of discontinued operations, including income tax expense of $7	42	–	–
Earnings (loss) from discontinued operations	$ 61	$ 83	$ (37)

B. 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. Proceeds from the sale were used for general corporate purposes. These assets included Powell Mountain Coal Co. and Dulcimer Land Co., which consisted of approximately 30,000 acres in Lee County, Va., and Harlan County, Ky. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets.

On May 1, 2006, we sold certain net assets of three of our coal mining businesses 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.

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 each of the years ended December 31, 2007 and 2006 was $1 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	2008	2007	2006
Revenues	$ 2	$ 28	$ 84
Loss before income taxes	$ (13)	$ (17)	$ (11)
Income tax benefit	4	6	7
Net loss from discontinued operations	(9)	(11)	(4)
Gain (loss) on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $16	7	–	(10)
Loss from discontinued operations	$ (2)	$ (11)	$ (14)

C. CCO - GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Energy 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 included 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 years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of the impairment recorded in 2006, respectively.

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 represented 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 represented 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 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 and 2006 was $11 million and $36 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense was $14 million for the year ended December 31, 2006. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	2008	2007	2006
Revenues	$ –	$ 407	$ 754
Loss before income taxes	$ (5)	$ (449)	$ (92)
Income tax benefit	2	166	35
Net loss from discontinued operations	(3)	(283)	(57)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2), $7 and $123, respectively	(2)	18	(226)
Loss from discontinued operations	$ (5)	$ (265)	$ (283)

D. 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., Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels). Proceeds from the sale were 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 was $13 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense was $16 million for the year ended December 31, 2006. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	2007	2006
Revenues	$ –	$ 192
Earnings before income taxes	$ –	$ 135
Income tax benefit (expense)	4	(53)
Net earnings from discontinued operations	4	82
(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

E. CCO - DESOTO AND ROWAN GENERATION FACILITIES

On May 8, 2006, we entered into definitive agreements to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (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. 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. 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 was $6 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the year ended December 31, 2006, was $3 million. Results of discontinued operations for DeSoto and Rowan for the year ended December 31 were as follows:

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

F. PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 Communications, Inc. 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 Communications, Inc 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. Results of discontinued operations for PT LLC for the year ended December 31 were as follows:

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

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3 Communications, Inc. 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.

G. 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 transported 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 years ended December 31, 2008 and 2007, we recorded additional gains of $1 million and $2 million, respectively, primarily related to the expiration of indemnifications.

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	**2008**	2007	2006
Revenues	$ –	$ –	$ 20
Earnings before income taxes	$ –	$ –	$ 11
Income tax expense	–	–	(4)
Net earnings from discontinued operations	–	–	7
Gain on disposal of discontinued operations, including income tax benefit (expense) of $1, $(1) and $(1), respectively	1	2	2
Earnings from discontinued operations	$ 1	$ 2	$ 9

H. PROGRESS RAIL

We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2008, we recorded an after-tax gain on disposal of $2 million. During the year ended December 31, 2006, we recorded an after-tax loss on disposal of $6 million. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

I. NET ASSETS TO BE DIVESTED

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of Coal Mining 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
Property, plant and equipment, net	38
Other assets	6
Assets to be divested	$ 52
Accrued expenses	$ 3
Long-term liabilities	5
Liabilities to be divested	$ 8

J. 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 nonrecourse 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. 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 year ended December 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 year ended December 31, 2008, based on the final value of the 2007 Section 29/45K tax credits.

During the year ended December 31, 2008, we recognized previously deferred 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. 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.

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 remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with FIN 46R, but record a 100 percent minority interest.

K. 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 a gain on these transactions of $4 million in the year ended December 31, 2006. 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 are reflected in discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

4. 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	**2008**	2007	**2008**	2007	**2008**	2007
Production plant	7-43	**$ 14,117**	$ 13,765	**$ 9,249**	$ 8,968	**$ 4,689**	$ 4,612
Transmission plant	17-75	**2,970**	2,684	**1,457**	1,361	**1,513**	1,323
Distribution plant	13-55	**8,028**	7,676	**4,330**	4,147	**3,698**	3,529
General plant and other	5-35	**1,211**	1,202	**662**	641	**549**	561
Utility plant in service		**$ 26,326**	$ 25,327	**$ 15,698**	$ 15,117	**$ 10,449**	$ 10,025

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 11).

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 9.2%, 8.8% and 8.7% in 2008, 2007 and 2006, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2008, 2007 and 2006.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3%, 2.4% and 2.3% in 2008, 2007 and 2006, respectively. The depreciation provisions related to utility plant were $578 million, $560 million and $533 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2008, 2007 and 2006. The depreciation provisions related to utility plant were $310 million, $303 million and $294 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D), 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, was 2.7% in 2008, 2007 and 2006. The depreciation provisions related to utility plant were $268 million, $257 million and $239 million in 2008, 2007 and 2006, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4D) and regulatory approved expenses (See Note 7C).

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, was $145 million, $139 million and $140 million for the years ended December 31, 2008, 2007 and 2006, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income. Amortization of nuclear fuel costs for the years ended December 31, 2008, 2007 and 2006 was $115 million, $110 million and $109 million, respectively, for PEC and $30 million, $29 million and $31 million, respectively, for PEF.

At December 31, 2008, PEF reflected $174 million of construction work in progress as recoverable regulatory assets pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

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)	2008	2007
Equipment (3-25 years)	$ 5	$ 6
Buildings (5-40 years)	9	9
Accumulated depreciation	(8)	(9)
Diversified business property, net	$ 6	$ 6

Diversified business depreciation expense was less than $1 million, $3 million and $2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

PEC

Net diversified business property was $6 million at December 31, 2008, and $6 million at December 31, 2007. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 5 to 40 years. Accumulated depreciation was $3 million and $2 million at December 31, 2008 and 2007, respectively. Diversified business depreciation expense was less than $1 million each in 2008, 2007 and 2006.

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:

2008 **(in millions)** **Subsidiary**	**Facility**	**Company Ownership Interest**	**Plant Investment**	**Accumulated Depreciation**	**Construction Work in Progress**
PEC	**Mayo**	**83.83%**	**$519**	**$278**	**$228**
PEC	**Harris**	**83.83%**	**3,187**	**1,603**	**21**
PEC	**Brunswick**	**81.67%**	**1,667**	**970**	**42**
PEC	**Roxboro Unit 4**	**87.06%**	**674**	**446**	**12**
PEF	**Crystal River Unit 3**	**91.78%**	**843**	**461**	**252**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**9**	**–**

2007 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$519	$270	$156
PEC	Harris	83.83%	3,175	1,581	21
PEC	Brunswick	81.67%	1,647	959	16
PEC	Roxboro Unit 4	87.06%	637	422	39
PEF	Crystal River Unit 3	91.78%	817	450	177
PEF	Intercession City Unit P11	66.67%	23	9	–

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, 2008 and 2007, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $28 million and $29 million, respectively. At December 31, 2008, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant totaled $19 million at PEF. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2007, at PEF. At December 31, 2008 and 2007, additional PEF-related asset retirement costs, net of accumulated depreciation, of $116 million and $121 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 $672 million and $804 million at December 31, 2008 and 2007, respectively, for PEC and $417 million and $580 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 2008, 2007 and 2006. 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, amortization and accretion expense, were $100 million, $96 million and $96 million in 2008, 2007 and 2006, respectively, for PEC and $33 million, $30 million and $27 million in 2008, 2007 and 2006, 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. In 2009, PEF will be required to file an updated depreciation study.

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)	**2008**	2007	**2008**	2007	**2008**	2007
Removal costs	**$ 1,478**	$ 1,410	**$ 864**	$ 794	**$ 614**	$ 616
Nonirradiated decommissioning costs	**146**	141	**84**	80	**62**	61
Dismantlement costs	**124**	125	**–**	–	**124**	125
Non-ARO cost of removal	**$ 1,748**	$ 1,676	**$ 948**	$ 874	**$ 800**	$ 802

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, September 2036 and October 2046 for Robinson, Brunswick Units No. 2 and No. 1 and Harris, respectively. On December 17, 2008, Harris received a 20-year extension from the NRC on its operating license, which extends the operating license through 2046. 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. In 2009, PEC will be required to file an updated nuclear decommissioning study.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing (See Note 7C). 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 2008 dollars, is $751 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. PEF submitted an application requesting a 20-year extension of this license on December 18, 2008. PEF expects a decision from the NRC in 2011. As part of this new estimate and assumed license extension, PEF increased its asset retirement cost and its ARO liability by approximately $19 million. 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. PEF expects to continue this suspension based on its planned 2009 base rate filing. 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 received an updated fossil dismantlement study estimate in 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing. PEF's reserve for fossil plant dismantlement was approximately $145 million and $144 million at December 31, 2008 and 2007, 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.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs (See Note 1D). In 2008, PEC and PEF reduced the ARO liabilities related to asbestos abatement costs for the fossil plants by $4 million and $8 million, respectively, due to an updated study. An additional ARO liability was recognized in 2008 for landfill capping costs identified by both PEC and PEF of $1 million and $6 million, respectively.

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.

The following table presents the changes to the AROs during the years ended December 31, 2008 and 2007. Revisions to prior estimates of the PEC and PEF regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2007	$ 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
Additions	**7**	**–**	**1**	**6**
Accretion expense	**79**	**–**	**62**	**17**
Revisions to prior estimates	**7**	**–**	**(4)**	**11**
Asset retirement obligations at December 31, 2008	**$ 1,471**	**$ –**	**$ 1,122**	**$ 349**

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 this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. 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 $37 million with respect to the primary coverage, $38 million with respect to the decontamination, decommissioning and excess property coverage, and $25 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 the plant, 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 $12.520 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 $117.5 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 $17.5 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 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified 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).

5. RECEIVABLES

Income taxes receivable and interest income receivables are not included in receivables. These amounts are included in prepayments and other current assets or shown separately on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Trade accounts receivable	**$ 648**	$ 616	**$ 350**	$ 310	**$ 298**	$ 276
Unbilled accounts receivable	**182**	175	**120**	111	**62**	59
Notes receivable	**2**	67	**–**	–	**–**	–
Derivatives accounts receivable	**–**	247	**–**	–	**–**	13
Other receivables	**53**	46	**38**	31	**13**	13
Allowance for doubtful receivables	**(18)**	(29)	**(6)**	(6)	**(11)**	(10)
Total receivables, net	**$ 867**	$ 1,122	**$ 502**	$ 446	**$ 362**	$ 351

6. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Fuel for production	**$ 614**	$ 455	**$ 287**	$ 210	**$ 327**	$ 245
Materials and supplies	**588**	520	**338**	284	**250**	236
Emission allowances	**37**	19	**8**	16	**29**	3
Total inventory	**$ 1,239**	$ 994	**$ 633**	$ 510	**$ 606**	$ 484

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy of $23 million and $65 million at December 31, 2008 and 2007, respectively, and PEC of $44 million at December 31, 2007.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $61 million, $14 million and $47 million, respectively, at December 31, 2008. Long-term emission allowances for Progress Energy, PEC and PEF were $32 million, $3 million and $29 million, respectively, at December 31, 2007.

On November 12, 2008, the FPSC approved PEF's petition for recovery of its CAIR expenses, including nitrogen oxides (NOx) emission allowance inventory, through the environmental cost recovery clause (ECRC) (See Note 7C).

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.

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 beginning in 2010 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.

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

Progress Energy

(in millions)	2008	2007
Deferred fuel cost – current (Notes 7B and 7C)	$ 335	$ 154
Nuclear deferral (Note 7C)	190	–
Environmental	8	–
Total current regulatory assets	533	154
Deferred fuel cost – long-term (Note 7B)	130	114
Deferred impact of ARO (Note 1D)	348	294
Income taxes recoverable through future rates (Note 14)	193	141
Loss on reacquired debt (Note 1D)	37	43
Storm deferral (Note 7C)	16	22
Postretirement benefits (Note 16)	1,042	212
Derivative mark-to-market adjustment (Note 17A)	697	18
Environmental (Notes 7C and 21A)	31	40
Investment in GridSouth (Note 7D)	19	22
Other	54	40
Total long-term regulatory assets	2,567	946
Deferred fuel cost – current (Note 7C)	–	(154)
Deferred energy conservation cost and other current regulatory liabilities	(6)	(19)
Total current regulatory liabilities	(6)	(173)
Non-ARO cost of removal (Note 4D)	(1,748)	(1,676)
Deferred impact of ARO (Note 1D)	(198)	(226)
Net nuclear decommissioning trust unrealized gains (Note 4D)	(28)	(351)
Derivative mark-to-market adjustment (Note 17A)	(26)	(200)
Storm reserve (Note 7C)	(129)	(63)
Other	(52)	(38)
Total long-term regulatory liabilities	(2,181)	(2,554)
Net regulatory assets (liabilities)	$ 913	$ (1,627)

PEC

(in millions)	2008	2007
Deferred fuel cost – current (Note 7B)	$ 207	$ 148
Deferred fuel cost – long-term (Note 7B)	130	114
Deferred impact of ARO (Note 1D)	343	294
Income taxes recoverable through future rates (Note 14)	62	51
Loss on reacquired debt (Note 1D)	16	18
Postretirement benefits (Note 16)	522	126
Derivative mark-to-market adjustment (Note 17A)	96	4
Investment in GridSouth (Note 7D)	19	22
Other	55	51
Total long-term regulatory assets	1,243	680
Non-ARO cost of removal (Note 4D)	(948)	(874)
Net nuclear decommissioning trust unrealized gains (Note 4D)	(21)	(188)
Derivative mark-to-market adjustment (Note 17A)	–	(20)
Other	(18)	(16)
Total long-term regulatory liabilities	(987)	(1,098)
Net regulatory assets (liabilities)	$ 463	$ (270)

PEF

(in millions)	2008	2007
Deferred fuel cost – current (Note 7C)	$ 128	$ 6
Nuclear deferral (Note 7C)	190	–
Environmental	8	–
Total current regulatory assets	326	6
Income taxes recoverable through future rates (Note 14)	131	90
Loss on reacquired debt (Note 1D)	21	25
Storm deferral (Note 7C)	14	16
Postretirement benefits (Note 16)	520	86
Derivative mark-to-market adjustment (Note 17A)	601	14
Environmental (Notes 7C and 21A)	21	30
Other	16	5
Total long-term regulatory assets	1,324	266
Deferred fuel cost – current (Note 7C)	–	(154)
Deferred energy conservation cost and other current regulatory liabilities	(6)	(19)
Total current regulatory liabilities	(6)	(173)
Non-ARO cost of removal (Note 4D)	(800)	(802)
Deferred impact of ARO (Note 1D)	(76)	(96)
~~Net nuclear decommissioning trust unrealized gains (Note 4D)~~	~~(7)~~	~~(163)~~
Derivative mark-to-market adjustment (Note 17A)	(26)	(180)
Storm reserve (Note 7C)	(129)	(63)
Other	(38)	(26)
Total long-term regulatory liabilities	(1,076)	(1,330)
Net regulatory assets (liabilities)	$ 568	$ (1,231)

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 of 12.75 percent. 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 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 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. 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 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 Association (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. 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 compliance costs of $813 million.

On July 10, 2008, PEC filed a petition with the NCUC requesting that the NCUC reconsider its order issued December 20, 2007, and terminate the requirement that PEC amortize any Clean Smokestacks Act compliance costs in excess of $569 million, and instead allow PEC to place into rate base all capital costs associated with its compliance with the Clean Smokestacks Act in excess of $569 million.

On September 5, 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks Act compliance costs. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC will not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful life of the assets.

For the years ended December 31, 2008, 2007 and 2006, PEC recognized amortization of $15 million, $34 million and $140 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008.

See Note 21B 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 asked 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. On June 26, 2008, the SCPSC approved PEC's request. Effective July 1, 2008, residential electric bills increased by $5.86 per 1,000 kilowatt-hours (kWh), or 6.1 percent, for fuel cost recovery. At December 31, 2008, PEC's South Carolina under-recovered deferred fuel balance was $15 million.

On June 6, 2008, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. Subsequently, PEC jointly filed a settlement agreement with CIGFUR, CUCA and the NCUC Public Staff. Under the terms of the settlement agreement, PEC will collect $203 million of deferred fuel costs ratably over a three-year period beginning December 1, 2008, compared with a one-year recovery period proposed in PEC's original request. Amounts to be collected in years beginning December 1, 2009 and 2010, will accrue interest. On November 14, 2008, the NCUC approved the settlement agreement. Effective December 1, 2008, residential electric bills increased by $8.79 per 1,000 kWh, or 9.1 percent. At December 31, 2008, PEC's North Carolina deferred fuel balance was $321 million, of which $130 million is expected to be collected after 2009 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

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 demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs 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. PEC has begun implementing a series of DSM and energy-efficiency programs and, as of December 31, 2008, has deferred $8 million of implementation and program costs for future recovery. In 2008, PEC filed for NCUC approval of multiple DSM and energy-efficiency programs. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the DSM and energy-efficiency filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency clause to recover the costs of these programs and a return on the costs. Although the NCUC is not expected to make a decision on this filing until first quarter 2009, on November 14, 2008, the NCUC approved PEC collecting the DSM and energy-efficiency related costs beginning December 1, 2008. On December 9, 2008, the North Carolina Public Staff filed an Agreement and Stipulation of Partial Settlement with PEC and some of the other parties to the proceedings. The NCUC held a hearing on the matter on January 7, 2009. If the rates being collected as of December 1, 2008, are approved, residential electric bills would increase by $0.74 per 1,000 kWh, or 0.8 percent. The increase in rates is subject to true-up in future proceedings. We cannot predict the outcome of this matter.

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 $1 million of implementation and program costs for future recovery in the South Carolina jurisdiction. On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. A hearing on this matter was held on February 12, 2009. We cannot predict the outcome of this matter.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

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 required PEC to submit its first annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance plan as part of its integrated resource plan, which was filed on September 2, 2008. Under the new rules, beginning in 2009, PEC will also be required to file an annual NC REPS compliance report demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC 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. Rates for the NC REPS clause will be set based on projected costs with true-up provisions. On June 6, 2008, and as amended on August 22, 2008, PEC filed an application with the NCUC for approval of a NC REPS clause to recover the costs of this program. On November 14, 2008, the NCUC approved a monthly charge per customer rather than a usage-based rate. Effective December 1, 2008, residential electric bills increased $0.36 per month.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery are $415 million and $585 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 $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $415 million for the North Carolina jurisdiction. The South Carolina aggregate minimum and maximum amounts of cost recovery are $115 million and $165 million, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2008, 2007 or 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction.

In October 2008, PEC filed, and the SCPSC approved, a petition to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets. As a result of the approval of this petition, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful life of the assets.

On October 13, 2008, the NCUC issued a Certificate of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximate 600-MW combined cycle dual fuel capable generating facility at its Richmond County generation site to provide additional generating and transmission capacity to meet the growing energy demands of southern and eastern North Carolina. PEC expects that the new generating and transmission capacity will be online by the second quarter of 2011.

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. On June 27, 2008, the FERC approved the settlement. The new rates were effective July 1, 2008, and increased 2008 revenues by $7 million.

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 thresholds in 2008, 2007 or 2006 and thus no revenues were subject to revenue sharing. Both the base threshold and the cap will be adjusted annually for rolling average 10-year retail kWh sales growth and were $1.664 billion and $1.716 billion, respectively, for 2008. 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 cost-recovery clause return calculations. PEF will use an authorized 11.75 percent return on equity 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 return on equity falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

On February 12, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2010. In its notice, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and that it intends to seek annual rate relief between $475 million to $550 million. PEF intends to file its case-in-chief on March 20, 2009. The request for increased base rates is based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems. If approved by the FPSC, the new base rates would increase residential bills by approximately $15.00 per 1,000 kWh, or 11 percent, effective January 1, 2010. We cannot predict the outcome of this matter.

As part of its February 12, 2009 notification, PEF also informed the FPSC that it may seek additional rate relief in 2009, primarily driven by the addition of its repowered Bartow power plant, which is expected to begin commercial operation in June 2009, and decreased sales and higher pension costs impacted by the current financial and credit crises. We cannot predict the outcome of this matter.

FUEL 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. On January 8, 2008, the FPSC issued an order approving PEF's request for a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008.

On May 30, 2008, PEF filed a petition with the FPSC requesting a mid-course correction to its fuel cost-recovery factors to recover an additional $213 million in 2008, primarily due to rising fuel costs. In accordance with a FPSC order, investor-owned utilities must file a notice with the FPSC if the year-end projected over- or under-recovery of fuel costs is expected to be greater than 10 percent of projected fuel revenues. The requested mid-course correction would have resulted in a residential fuel rate increase of $12.07 per 1,000 kWh for the period August through December 2008. On July 1, 2008, the FPSC approved recovery of the $213 million projected year-end under-recovery, but allowed PEF to recover 50 percent in 2008 and 50 percent in 2009. Therefore, the increase in the fuel rate for the period August through December 2008 was $6.03 per 1,000 kWh. This increase was partially offset by the expiration of PEF's storm cost-recovery surcharge of $3.61 per 1,000 kWh effective August 2008. Consequently, beginning with the first billing cycle in August and including gross receipts tax, residential electric bills increased by $2.48 per 1,000 kWh, or 2.29 percent. As discussed in "Base Rate Agreement," residential base rates increased effective January 1, 2008, due to specified generation facilities placed in service in 2007. The costs of certain of these facilities had previously been recovered through the fuel clause.

On October 15, 2008, PEF filed a request with the FPSC to seek approval of a cost adjustment for the under-recovery of fuel costs in 2008 and other recovery-clause factors. PEF asked the FPSC to approve an increase in residential electric bills by $27.28 per 1,000 kWh, or 24.7 percent, effective January 1, 2009. The increase in residential bills is primarily due to increases of $14.09 per 1,000 kWh for the projected recovery of fuel costs, $9.74 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause and $2.50 per 1,000 kWh for the projected recovery through the ECRC. The increase in the capacity cost-recovery clause is primarily the result of projected costs to be incurred in 2009 under the nuclear cost-recovery rule discussed below for the proposed Levy Units 1 and 2 and the CR3 uprate less the projected reduction in capacity costs. The increase in the ECRC is primarily due to the recovery of emission allowance costs (See Note 21B) and the return on assets expected to be placed in service in 2009. The FPSC issued orders in November and December 2008 to approve the cost adjustment. At December 31, 2008, PEF's under-recovered deferred fuel balance was $128 million.

On February 18, 2009, PEF filed a request with the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $207 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices, and to defer until 2010 the recovery of $200 million of Levy nuclear preconstruction costs, which the FPSC had authorized to be collected in 2009. If approved, the request would reduce residential customers' fuel charges by $6.90 per 1,000 kWh, and would reduce the nuclear cost-recovery charge by $7.80 per 1,000 kWh, starting with the first April billing cycle. Commercial and industrial customers would see similar reductions. We cannot predict the outcome of this matter.

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 October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC 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. The refund was returned to ratepayers through a reduction of prior year under-recovered fuel costs. 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. PEF believes its coal procurement practices have been prudent. A hearing on PEF's 2006 and 2007 coal purchases has been scheduled for April 13-15, 2009. On February 2, 2009, the OPC filed direct testimony in this hearing alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 plants. We cannot predict the outcome of this matter.

NUCLEAR COST RECOVERY

The FPSC has authorized alternative cost-recovery mechanisms for preconstruction and construction carrying cost of nuclear power plants. Accordingly, at December 31, 2008, PEF reflected $190 million of nuclear-related costs as a current regulatory asset, of which $174 million represents construction work in progress (See Note 4A). The total $190 million of nuclear-related costs was comprised of $9 million related to the CR3 uprate and $181 million related to Levy.

CR3 Uprate

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3 and bid rule exemption, and for 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 petition filed with the FPSC included a preliminary project estimate of approximately $382 million. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, at a cost of $9 million. PEF will apply for the required license amendment for the third stage's design modification. After PEF's completion of a transmission study and additional engineering studies, the current project estimate of fully loaded costs is $364 million.

On February 29, 2008, PEF filed a petition amending its recovery request and asked for recovery of costs incurred in 2007 and 2006 through the capacity cost-recovery clause under Florida's comprehensive energy legislation and the FPSC's nuclear cost-recovery rule. On August 19, 2008, the FPSC granted PEF's petition to amend its request to recover costs for the nuclear uprate project under the nuclear cost-recovery rule. On May 1, 2008, PEF filed with the FPSC for an increase in the capacity cost-recovery clause for estimated costs incurred in 2008 and projected costs to be incurred in 2009 under the FPSC nuclear cost-recovery rule. PEF petitioned the FPSC to approve a $25 million increase in the capacity cost-recovery revenue requirement for costs associated with subsequent stages of the CR3 uprate.

On September 19, 2008, PEF filed a petition with the FPSC to approve a base rate increase for the remaining revenue requirements for the first-stage costs. PEF's 2008 revenue requirements for recovery of the first stage's costs were included in the capacity cost-recovery clause. On October 28, 2008, the FPSC approved a $1 million base rate increase for costs associated with the first stage of the CR3 uprate. Base rates increased for residential customers by $0.04 per 1,000 kWh, or 0.1 percent, beginning in January 2009. On November 12, 2008, the FPSC issued an order to approve $24 million for costs associated with the CR3 uprate in establishing PEF's 2009 capacity cost-recovery clause factor.

Levy 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. 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 PEF's customers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. As stated in the petition, Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 is approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. The FPSC issued the final order granting the petition for the Determination of Need for the proposed nuclear units on August 12, 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 Levy. PEF filed the petition to assist the FPSC in the timely and adequate review of the proposed project's costs recoverable under the 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 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for Levy, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

As discussed above in "Fuel Cost Recovery," on February 18, 2009, PEF filed a request with the FPSC to defer the recovery of $200 million of Levy nuclear preconstruction costs.

STORM COST RECOVERY

In 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 four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007 and 2006, PEF recorded amortization of $75 million and $122 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, was 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. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. At December 31, 2008, PEF's storm reserve totaled $129 million.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised 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 increased 2008 revenues by $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. 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. Consequently, in 2007, PEC recorded an $11 million charge to amortization expense. On June 4, 2008, the NCUC issued an order granting PEC the same accounting treatment to its GridSouth development costs. In accordance with the OATT settlement discussed above, in July 2008, PEC began amortization and recovery of the wholesale portion of PEC's GridSouth development costs over a five-year period. The impact of this wholesale amortization was $1 million in 2008 and is estimated to be $2 million annually during the remaining amortization period. PEC's recorded investment in GridSouth totaled $19 million and $22 million at December 31, 2008 and 2007, respectively.

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 December 17, 2008, the NRC issued a 20-year extension on the operating license for Harris, which extends the operating license through 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year extension from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

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 2008 and 2007; 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, 2008 and 2007, 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 2008 or 2007.

Goodwill was previously allocated to our former CCO-Georgia Operations reporting unit, which was comprised of four nonregulated generating plants. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed an interim 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 3C).

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 3A). 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.

9. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2008 and 2007, we had 500 million shares of common stock authorized under our charter, of which 264 million shares and 260 million shares, respectively, were outstanding. During 2008, 2007 and 2006, respectively, we issued approximately 3.7 million, 3.7 million and 4.2 million shares of common stock, resulting in approximately $132 million, $151 million and $185 million in proceeds. Included in these amounts for 2008, 2007 and 2006, respectively, were approximately 3.1 million, 1.0 million and 1.6 million shares for proceeds of approximately $131 million, $46 million and $70 million, issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2008, there were no significant restrictions on the use of retained earnings (See Note 11B).

PEC

At December 31, 2008 and 2007, 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, 2008, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEC.

PEF

At December 31, 2008 and 2007, 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, 2008, there were no significant restrictions on the use of retained earnings. See Note 11B 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, 2008 and 2007, 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 1.1 million and 1.7 million ESOP suspense shares at December 31, 2008 and 2007, respectively, with a fair value of $45 million and $82 million, respectively. ESOP shares allocated to plan participants totaled 12.6 million and 10.6 million at December 31, 2008 and 2007, 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 $8 million, $23 million and $14 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $34 million, $30 million and $23 million for the years ended December 31, 2008, 2007 and 2006, 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 $5 million, $14 million and $8 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $21 million, $18 million and $13 million for the years ended December 31, 2008, 2007 and 2006, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $1 million, $4 million and $2 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $7 million, $6 million and $4 million for the years ended December 31, 2008, 2007 and 2006, 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, 2008, 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	1.7	$43.99
Canceled	–	44.38
Exercised	(0.1)	43.83
Options outstanding, December 31	1.6	43.99
Options exercisable, December 31	1.6	43.99

The options outstanding and exercisable at December 31, 2008, had a weighted-average remaining contractual life of 4.0 years. Aggregate intrinsic value as of December 31, 2008, was not significant. Total intrinsic value of options exercised during the years ended December 31, 2007 and 2006, respectively, was $17 million and $10 million. The total intrinsic value of options exercised during the year ended December 31, 2008, was not significant.

Compensation cost, for expense purposes subsequent to the adoption of SFAS No. 123R, 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.

At December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2008 or 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.

Cash received from the exercise of stock options totaled $1 million, $105 million and $115 million, respectively, during the years ended December 31, 2008, 2007 and 2006. 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 deduction for stock option exercises for the year ended December 31, 2008, 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 2008 or 2007.

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 2008 or 2007.

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 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. We issue new shares of common stock to satisfy the requirements of the PSSP program. 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 $2 million, $3 million and $4 million were paid in the years ended December 31, 2008, 2007 and 2006, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2008, 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	1,629,995	$44.97
Granted	271,964	42.41
Vested	(441,435)	44.23
Paid(b)	(228,793)	50.70
Forfeited	(113,127)	44.76
Ending balance	1,118,604	46.46

(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 131,881 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2007 and 2006, the weighted-average grant date fair value of stock-settled performance shares granted was $50.70 and $44.27, respectively.

The Restricted Stock Award 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, 2008, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	268,635	$43.77
Granted	–	–
Vested	(71,134)	43.29
Forfeited	(5,400)	44.63
Ending balance	192,101	43.93

For the years ended December 31, 2007 and 2006, the weighted-average grant date fair value of restricted stock granted was $49.54 and $44.51, respectively.

The total fair value of restricted stock awards vested during the years ended December 31, 2008, 2007 and 2006 was $3 million, $13 million and $4 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the year ended December 31, 2006. Cash expended to purchase shares for 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award 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. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, 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, 2008, and changes during the year then ended, is presented below:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	824,458	$50.29
Granted	489,603	42.48
Vested	(187,318)	46.67
Forfeited	(50,207)	50.55
Ending balance	1,076,536	46.86

The total fair value of RSUs vested during the year ended December 31, 2008, was $9 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2008.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $31 million for the year ended December 31, 2008, with a recognized tax benefit of $12 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $64 million with a recognized tax benefit of $24 million and $25 million, with a recognized tax benefit of $10 million, for the years ended December 31, 2007 and 2006, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2008, there was $34 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 1.57 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $18 million for the year ended December 31, 2008, with a recognized tax benefit of $7 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $38 million with a recognized tax benefit of $15 million and $14 million, with a recognized tax benefit of $6 million, for the years ended December 31, 2007 and 2006, 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 $13 million for the year ended December 31, 2008, with a recognized tax benefit of $5 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $21 million with a recognized tax benefit of $8 million and $7 million, with a recognized tax benefit of $3 million, for the years ended December 31, 2007 and 2006, respectively. 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)	2008	2007	2006
Weighted-average common shares – basic	260.3	256.1	250.4
Net effect of dilutive stock-based compensation plans	0.5	0.6	0.4
Weighted-average shares – fully diluted	260.8	256.7	250.8

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 ESOP shares totaled 1.2 million, 1.8 million and 2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. There were 1.6 million, 0.1 million and 1.8 million stock options outstanding at December 31, 2008, 2007 and 2006, 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)	2008	2007	2008	2007	2008	2007
Loss on cash flow hedges	$ (57)	$ (23)	$ (35)	$ (10)	$ (1)	$ (8)
Pension and other postretirement benefits	(58)	(13)	–	–	–	–
Other	(1)	2	–	–	–	–
Total accumulated other comprehensive loss	$ (116)	$ (34)	$ (35)	$ (10)	$ (1)	$ (8)

10. 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, 2008 and 2007, preferred stock outstanding consisted of the following:

	Shares		Redemption	
(dollars in millions, except share and per share data)	Authorized	Outstanding	Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,0000			
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

11. 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, 2008):

(in millions)		2008	2007
Parent			
Senior unsecured notes, maturing 2010-2031	6.96%	$ **2,600**	$ 2,600
Draws on revolving credit agreement, expiring 2012	2.52%	**100**	
Unamortized premium and discount, net		**(4)**	(3)
Long-term debt, net		**2,696**	2,597
PEC			
First mortgage bonds, maturing 2009-2038	5.74%	**2,325**	2,000
Pollution control obligations, maturing 2017-2024	2.25%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes			300
Miscellaneous notes	6.01%	**22**	22
Unamortized premium and discount, net		**(7)**	(8)
Current portion of long-term debt			(300)
Long-term debt, net		**3,509**	3,183
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	**3,800**	2,380
Pollution control obligations, maturing 2018-2027	1.63%	**241**	241
Senior unsecured notes			450
Medium-term notes, maturing 2028	6.75%	**150**	152
Unamortized premium and discount, net		**(9)**	(5)
Current portion of long-term debt			(532)
Long-term debt, net		**4,182**	2,686
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(37)**	(38)
Long-term debt, net		**272**	271
Progress Capital Holdings, Inc.			
Medium-term notes			45
Current portion of long-term debt			(45)
Long-term debt, net			
Progress Energy consolidated long-term debt, net		$ **10,659**	$ 8,737

At December 31, 2008, the Parent had a revolving credit agreement (RCA) used to support its commercial paper borrowings. We classified $100 million of the $600 million outstanding under the Parent's RCA as long-term debt. Settlement of a portion of this obligation did not require the use of working capital in 2009 as $100 million of the proceeds from the January 12, 2009 equity issuance was used to reduce RCA borrowings. No amount was outstanding under the Parent's RCA at December 31, 2007. Additionally, we classified PEC's $400 million 5.95% Senior Notes, due March 1, 2009, as long-term debt, as the maturity will be paid with the proceeds of PEC's $600 million January 15, 2009 debt issuance discussed below

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 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

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 June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding money pool balance and for general corporate purposes.

At December 31, 2008 and 2007, we had committed lines of credit used to support our commercial paper borrowings. As a result of financial and economic conditions in 2008, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets, which is reflected in the outstanding borrowings under our credit facilities as shown in the table below. As discussed above, of the $600 million outstanding, $100 million was classified as long-term debt at December 31, 2008. We will continue to monitor the commercial paper and short-term credit markets to determine when to repay the outstanding balance of the RCA loan, while maintaining an appropriate level of liquidity. At December 31, 2007, 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 RCAs and available capacity at December 31, 2008:

(in millions)	Description	Total	Outstanding(a)	Reserved(b)	Available
Parent	Five-year (expiring 5/3/12)	$ 1,130	$ 600	$ 99	$ 431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$ 2,030	$ 600	$ 580	$ 850

(a) In February 2009, the Parent repaid $100 million of its outstanding RCA borrowings.
(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had $30 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 the short-term portion of our outstanding RCA borrowings, our outstanding commercial paper and related weighted-average interest rates at December 31:

(in millions)	2008			2007		
Parent	2.81%	$	569	5.48%	$	201
PEC	4.36%		110			–
PEF	4.41%		371			–
Total	3.54%	$	1,050		$	201

The following table presents the aggregate maturities of long-term debt at December 31, 2008:

(in millions)		Progress Energy Consolidated		PEC		PEF
2009	$	–	$	–	$	–
2010		406		6		300
2011		1,000		–		300
2012		1,050		500		–
2013		825		400		425
Thereafter		7,435		2,610		3,166
Total	$	10,716	$	3,516	$	4,191

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent'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, 2008, 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)
Parent	68%	57.8%
PEC	65%	45.5%
PEF	65%	58.6%

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees 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 the Parent 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. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only 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 the Parent'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 the Parent, 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 the Parent'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, 2008, the Parent had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by the Parent'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, 2008, 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 the 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, 2008, PEC's common stock equity was approximately 54.7 percent of total capitalization. At December 31, 2008, 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, 2008, 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 the 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, 2008, PEF's common stock equity was approximately 44 6 percent of total capitalization. At December 31, 2008, 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, 2008, PEC and PEF had a total of \$2 994 billion and \$4.041 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.

12. INVESTMENTS

A. INVESTMENTS

At December 31, 2008 and 2007, 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)	**2008**	2007	**2008**	2007	**2008**	2007
Nuclear decommissioning trust (See Note 4D)	**$ 1,089**	$ 1,384	**$ 672**	$ 804	**$ 417**	$ 580
Equity method investments (a)	**22**	23	**9**	11	**2**	2
Cost investments (b)	**7**	8	**3**	3	**–**	–
Company-owned life insurance (c)	**49**	51	**34**	34	**–**	–
Benefit investment trusts (d)	**184**	199	**85**	80	**30**	39
Marketable debt securities	**1**	1	**1**	1	**–**	–
Total	**$ 1,352**	$ 1,666	**$ 804**	$ 933	**$ 449**	$ 621

(a) 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).
(b) Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
(c) Investments in company-owned life insurance are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the nature of the investment.
(d) Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 2008 and 2007, $142 million and $155 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF 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. There were no material other-than-temporary impairments in 2008, 2007 or 2006.

13. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $10.659 billion and $9.614 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11.260 billion and $9.897 billion at December 31, 2008 and 2007, 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 the Utilities' nuclear plants (See Note 4D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at fair value. 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 fair value. Our available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ 518	$ (93)	$ 134	$ 559
Debt securities	478	(27)	15	466
Cash equivalents	114	–	–	114
Total	$ 1,110	$ (120)	$ 149	$ 1,139

2007 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ 475	$ (10)	$ 354	$ 819
Debt securities	578	(4)	11	585
Cash equivalents	18	–	–	18
Total	$ 1,071	$ (14)	$ 365	$ 1,422

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; $118 million of the unrealized losses and $148 million of the unrealized gains for 2008 and all unrealized losses and gains for 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $374 million and $243 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)		
Due in one year or less	$	2
Due after one through five years		183
Due after five through 10 years		126
Due after 10 years		155
Total	$	466

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)		**2008**		2007		2006
Proceeds	$	**1,092**	$	1,334	$	2,547
Realized gains		**29**		35		33
Realized losses		**86**		23		19

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the years ended December 31, 2007 and 2006, our proceeds from the sale of these securities were $399 million and $1.7 billion, respectively. For the year ended December 31, 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2008, 2007 and 2006 for investments in these benefit investment 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, 2008 and 2007, 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 $3.509 billion and $3.483 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.690 billion and $3.545 billion at December 31, 2008 and 2007, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 4D). 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 fair value. 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 fair value. PEC's available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ 314	$ (55)	$ 75	$ 334
Debt securities	249	(10)	11	250
Cash equivalents	105	–	–	105
Total	$ 668	$ (65)	$ 86	$ 689

2007 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ 262	$ (6)	$ 191	$ 447
Debt securities	344	(3)	6	347
Cash equivalents	11	–	–	11
Total	$ 617	$ (9)	$ 197	$ 805

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; all of the unrealized losses and gains for 2008 and 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $191 million and $166 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 2
Due after one through five years	142
Due after five through 10 years	57
Due after 10 years	49
Total	$ 250

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)	2008	2007	2006
Proceeds	$ **579**	$ 609	$ 995
Realized gains	**12**	12	21
Realized losses	**48**	13	10

Previously, PEC invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the year ended December 31, 2006, PEC's proceeds from the sale of these securities were $531 million. For the years ended December 31, 2008 and 2007, PEC's proceeds were primarily related to nuclear decommissioning trusts. 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, 2008, PEC did not have any other securities. At December 31, 2007, 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 $4.182 billion and $3.218 billion at December 31, 2008 and 2007,~~ respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.546 and $3.239 billion at December 31, 2008 and 2007, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 4D). 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 fair value. PEF's available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2008 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ **204**	$ **(38)**	$ **59**	$ **225**
Debt securities	**189**	**(15)**	**3**	**177**
Cash equivalents	**9**	**–**	**–**	**9**
Total	$ **402**	$ **(53)**	$ **62**	$ **411**

2007 (in millions)	Book Value	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$ 213	$ (4)	$ 163	$ 372
Debt securities	194	(1)	5	198
Cash equivalents	7	–	–	7
Total	$ 414	$ (5)	$ 168	$ 577

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment applicable to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments: all of the unrealized losses and gains for 2008 and 2007 relate to the nuclear decommissioning trusts.

The aggregate fair value of investments that related to the 2008 and 2007 unrealized losses were $165 million and $77 million, respectively.

At December 31, 2008, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)		
Due in one year or less	$	–
Due after one through five years		34
Due after five through 10 years		58
Due after 10 years		85
Total	$	177

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)	2008	2007	2006
Proceeds	$ 394	$ 535	$ 509
Realized gains	16	22	12
Realized losses	36	9	8

Previously, PEF invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the years ended December 31, 2007 and 2006, PEF's proceeds from the sale of these securities were $329 million and $235 million, respectively. For the year ended December 31, 2008, all of PEF's proceeds were related to nuclear decommissioning trusts. 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, 2008, PEF did not have any other securities. At December 31, 2007, PEF's other securities had no investments in a continuous loss position for greater than 12 months.

B. 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 delayed for us the effective date of SFAS No. 157 until January 1, 2009, for all nonfinancial assets and nonfinancial liabilities, except for those 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, AROs initially recognized at fair value, and nonfinancial liabilities for exit and disposal costs and indemnifications initially measured at fair value. The January 1, 2009, adoption of SFAS No. 157 for nonrecurring nonfinancial assets and liabilities did not 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 financial instruments 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 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.

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 December 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	$ –	$ 10	$ –	$ 10
Nuclear decommissioning trust funds	592	497	–	1,089
Other marketable securities	16	38	–	54
Total assets	$ 608	$ 545	$ –	$ 1,153
Liabilities				
Commodity derivatives	$ –	$ (647)	$ (41)	$ (688)
Interest rate derivatives	–	(65)	–	(65)
CVO derivatives	–	(34)	–	(34)
Total liabilities	$ –	$ (746)	$ (41)	$ (787)

PEC

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds	$ 368	$ 304	$ –	$ 672
Other marketable securities	2	–	–	2
Total assets	$ 370	$ 304	$ –	$ 674
Liabilities				
Commodity derivatives	$ –	$ (77)	$ (22)	$ (99)
Interest rate derivatives	–	(35)	–	(35)
Total liabilities	$ –	$ (112)	$ (22)	$ (134)

PEF

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ –	$ 10	$ –	$ 10
Nuclear decommissioning trust funds	224	193	–	417
Other marketable securities	1	–	–	1
Total assets	$ 225	$ 203	$ –	$ 428
Liabilities				
Commodity derivatives	$ –	$ (570)	$ (19)	$ (589)

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 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 17 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 12A. 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 primarily 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, as discussed in Note 15. 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 for the 12 months ended December 31, 2008.

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	(102)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	35
Derivatives, net at December 31, 2008	$ (41)

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	(32)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	4
Derivatives, net at December 31, 2008	$(22)

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	(70)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	31
Derivatives, net at December 31, 2008	$(19)

Substantially all unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment.

Transfers out of Level 3 represent existing assets or liabilities previously classified as Level 3 for which the lowest significant input became observable during the period.

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, "Accounting for Income Taxes" (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)	2008	2007
Deferred income tax assets		
ARO liability	$ **264**	$ 146
Compensation accruals	**100**	101
Derivative instruments	**286**	–
Environmental remediation liability	**21**	32
Income taxes refundable through future rates	**111**	324
Pension and other postretirement benefits	**544**	306
Unbilled revenue	**61**	59
Other	**170**	122
Federal income tax credit carry forward	**802**	836
State net operating loss carry forward (net of federal expense)	**64**	87
Valuation allowance	**(55)**	(79)
Total deferred income tax assets	**2,368**	1,934
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,665)**	(1,482)
Deferred fuel recovery	**(186)**	(64)
Deferred nuclear cost recovery	**(73)**	–
Derivative instruments	**–**	(59)
Income taxes recoverable through future rates	**(959)**	(317)
Investments	**(6)**	(99)
Prepaid pension costs	**–**	(18)
Other	**(62)**	(56)
Total deferred income tax liabilities	**(2,951)**	(2,095)
Total net deferred income tax liabilities	$ **(583)**	$ (161)

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

(in millions)		2008		2007
Current deferred income tax assets, included in prepayments and other current assets	$	**96**	$	45
Noncurrent deferred income tax assets, included in other assets and deferred debits		**32**		65
Current deferred income tax liabilities, included in other current liabilities		**(1)**		(5)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities		**(710)**		(266)
Total net deferred income tax liabilities	$	**(583)**	$	(161)

At December 31, 2008, the federal income tax credit carry forward includes $802 million of alternative minimum tax credits that do not expire.

At December 31, 2008, we had gross state net operating loss carry forwards of $1.5 billion that will expire during the period 2009 through 2028.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net reduction of $24 million in our valuation allowances during 2008:

- We increased our valuation allowances by $12 million during 2008. Additional valuation allowances of $9 million were recorded related to PVI's 2007 state net operating loss carry forward. Additional valuation allowances of $3 million were recorded to fully offset state net operating loss and state capital loss carry forwards generated during 2008.

- We reduced our valuation allowances and deferred income tax assets by $36 million during 2008 due to the ceasing of business operations in various state taxing jurisdictions. The $36 million of valuation allowances were previously recorded to fully offset $36 million of state deferred income tax assets related to our terminal, coal mining and synthetic fuel businesses. During 2008, we sold our terminal and remaining coal mining businesses and dissolved our synthetic fuel businesses, which caused us to cease business operations in various state taxing jurisdictions. We believe that we will not realize the deferred income tax assets for those jurisdictions, and accordingly we reduced our total deferred income tax assets and corresponding valuation allowances by $36 million, which had no net impact on total deferred income tax assets.

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:

	2008	2007	2006
Effective income tax rate	**33.7%**	32.3%	37.5%
State income taxes, net of federal benefit	**(3.8)**	(2.8)	(3.5)
Investment tax credit amortization	**1.0**	1.1	1.3
Employee stock ownership plan dividends	**1.0**	1.1	1.3
Domestic manufacturing deduction	**0.3**	1.0	0.4
AFUDC equity	**2.5**	0.7	(0.1)
Other differences, net	**0.3**	1.6	(1.9)
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)		2008		2007		2006
Current – federal	$	38	$	285	$	394
– state		12		36		70
Deferred – federal		305		13		(94)
– state		49		11		(17)
Investment tax credit		(12)		(12)		(12)
State net operating loss carry forward		(6)		1		(2)
Beginning-of-the-year valuation allowance change		9		–		–
Total income tax expense	$	395	$	334	$	339

We previously recorded a deferred income tax asset for a state net operating loss carry forward upon the sale of PVI's nonregulated generation facilities and energy marketing and trading operations During 2008, we recorded an additional deferred income tax asset of $6 million related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings As previously discussed, we also evaluated this state net operating loss carry forward and recorded a partial valuation allowance of $9 million.

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

- Taxes related to discontinued operations recorded net of tax for 2008, 2007 and 2006, which are presented separately in Notes 3A through 3G.
- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, 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. No net current tax benefit was recorded in common stock during 2008.
- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48) on January 1, 2007.

At December 31, 2008, our liability for unrecognized tax benefits was $104 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $8 million. At December 31, 2007, our liability for unrecognized tax benefits was $93 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $10 million. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2008 and 2007:

(in millions)	2008	2007
Unrecognized tax benefits at beginning of period	$ 93	$ 126
Gross amounts of increases as a result of tax positions taken in a prior period	17	32
Gross amounts of decreases as a result of tax positions taken in a prior period	(11)	(41)
Gross amounts of increases as a result of tax positions taken in the current period	8	22
Gross amounts of decreases as a result of tax positions taken in the current period	(2)	(32)
Amounts of net increases (decreases) relating to settlements with taxing authorities	1	(14)
Reductions as a result of a lapse of the applicable statute of limitations	(2)	–
Unrecognized tax benefits at end of period	$ 104	$ 93

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 2003 forward. The Internal Revenue Service (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, 2009.

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 2008 and 2007, the net interest expense related to unrecognized tax benefits was $4 million and $1 million, respectively, of which a respective $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. During 2007, there were no penalties related to unrecognized tax benefits. At December 31, 2008 and 2007, we had accrued $27 million and $23 million, respectively, 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)	2008	2007
Deferred income tax assets		
ARO liability	$ 244	$ 140
Compensation accruals	52	55
Derivative instruments	64	4
Income taxes refundable through future rates	10	83
Pension and other postretirement benefits	262	166
Unbilled revenue	18	18
Other	38	36
Federal income tax credit carry forward	–	1
Total deferred income tax assets	688	503
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,162)	(1,013)
Deferred fuel recovery	(132)	(60)
Income taxes recoverable through future rates	(451)	(218)
Investments	(8)	(74)
Other	(12)	(7)
Total deferred income tax liabilities	(1,765)	(1,372)
Total net deferred income tax liabilities	$ (1,077)	$ (869)

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

(in millions)	2008	2007
Current deferred income tax assets, included in prepayments and other current assets	$ –	$ 26
Current deferred income tax liabilities, included in other current liabilities	(5)	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(1,072)	(895)
Total net deferred income tax liabilities	$ (1,077)	$ (869)

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

	2008	2007	2006
Effective income tax rate	35.8%	37.1%	36.7%
State income taxes, net of federal benefit	(2.7)	(2.3)	(2.3)
Investment tax credit amortization	0.7	0.7	0.8
Domestic manufacturing deduction	0.5	1.1	0.6
Other differences, net	0.7	(1.6)	(0.8)
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)		2008		2007		2006
Current – federal	$	87	$	235	$	285
– state		7		19		39
Deferred – federal		181		34		(42)
– state		29		13		(11)
Investment tax credit		(6)		(6)		(6)
Total income tax expense	$	298	$	295	$	265

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

- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, 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. No net current tax benefit was recorded in common stock during 2008.
- Taxes of $6 million that reduced retained earnings, due to the cumulative effect of adopting the provisions of FIN 48 on January 1, 2007.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $74 million at December 31, 2008. PEC's intercompany tax payable was approximately $27 million at December 31, 2007.

At December 31, 2008, PEC's liability for unrecognized tax benefits was $38 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $5 million. At December 31, 2007, PEC's liability for unrecognized tax benefits was $41 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $9 million. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2008 and 2007:

(in millions)		2008		2007
Unrecognized tax benefits at beginning of period	$	41	$	43
Gross amounts of increases as a result of tax positions taken in a prior period		5		3
Gross amounts of decreases as a result of tax positions taken in a prior period		(10)		(15)
Gross amounts of increases as a result of tax positions taken in the current period		4		22
Gross amounts of decreases as a result of tax positions taken in the current period		(1)		(5)
Amounts of net increases (decreases) relating to settlements with taxing authorities		1		(7)
Reductions as a result of a lapse of the applicable statute of limitations		(2)		–
Unrecognized tax benefits at end of period	$	38	$	41

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 2003 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 12-month period ending December 31, 2009.

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 2008 and 2007, the interest benefit recorded related to unrecognized tax benefits was $1 million and $4 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2008 and 2007, PEC had accrued $7 million and $8 million, respectively, 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)	2008	2007
Deferred income tax assets		
Compensation accruals	$ **23**	$ 21
Derivative instruments	**222**	–
Environmental remediation liability	**14**	18
Income taxes refundable through future rates	**54**	190
Pension and other postretirement benefits	**192**	142
Reserve for storm damage	**54**	25
Unbilled revenue	**43**	41
Other	**64**	56
Total deferred income tax assets	**666**	493
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(490)**	(451)
Deferred fuel recovery	**(54)**	(4)
Deferred nuclear cost recovery	**(73)**	–
Derivative instruments	**–**	(64)
Income taxes recoverable through future rates	**(508)**	(99)
Investments	**(3)**	(63)
Prepaid pension costs	**–**	(86)
Other	**(36)**	(33)
Total deferred income tax liabilities	**(1,164)**	(800)
Total net deferred income tax liabilities	$ **(498)**	$ (307)

The above amounts were classified on the Balance Sheets as follows:

(in millions)	2008	2007
Current deferred income tax assets, included in prepayments and other current assets	$ **74**	$ 39
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(572)**	(346)
Total net deferred income tax liabilities	$ **(498)**	$ (307)

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

	2008	2007	2006
Effective income tax rate	**32.0%**	31.2%	37.0%
State income taxes, net of federal benefit	**(3.1)**	(3.3)	(3.6)
Investment tax credit amortization	**1.1**	1.3	1.2
Domestic manufacturing deduction	**0.2**	0.8	0.3
AFUDC equity	**5.4**	2.6	0.7
Other differences, net	**(0.6)**	2.4	(0.6)
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)	2008	2007	2006
Current – federal	**$ 39**	$ 160	$ 207
– state	**12**	28	34
Deferred – federal	**121**	(33)	(36)
– state	**15**	(5)	(6)
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense	**$ 181**	$ 144	$ 193

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

- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, 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 and 2006, 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. No net current tax benefit was recorded in common stock during 2008.
- Taxes of less than $1 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting the provisions of FIN 48 on January 1, 2007.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $47 million and $41 million at December 31, 2008 and 2007, respectively.

At December 31, 2008, PEF's liability for unrecognized tax benefits was $62 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $2 million. At December 31, 2007, PEF's liability for unrecognized tax benefits was $55 million, and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $3 million. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2008 and 2007:

(in millions)	2008	2007
Unrecognized tax benefits at beginning of period	$ 55	$ 72
Gross amounts of increases as a result of tax positions taken in a prior period	6	23
Gross amounts of decreases as a result of tax positions taken in a prior period	(1)	(4)
Gross amounts of increases as a result of tax positions taken in the current period	3	2
Gross amounts of decreases as a result of tax positions taken in the current period	(1)	(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 end of period	$ 62	$ 55

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 2003 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 12-month period ending December 31, 2009.

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 or less, with the amortization included in interest charges on the Statements of Income. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense on the Statement of Income. Penalties are included in other, net on the Statements of Income. During 2008 and 2007, interest expense recorded as a regulatory asset was $1 million and $15 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2008 and 2007, PEF had accrued $19 million and $18 million, respectively, 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 CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, of which three were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 3A).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, 2008 and 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million.

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuel facilities (See Note 3J). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. 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 payments held in trust for 2008 and 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2008.

16. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

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. 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)	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$ 46**	$ 46	$ 45	**$ 8**	$ 7	$ 9
Interest cost	**128**	123	117	**34**	32	33
Expected return on plan assets	**(170)**	(155)	(148)	**(6)**	(6)	(6)
Amortization of actuarial loss(a)	**8**	15	18	**1**	2	4
Other amortization, net (a)	**2**	2	–	**5**	5	5
Net periodic cost	**$ 14**	$ 31	$ 32	**$ 42**	$ 40	$ 45

(a)Adjusted to reflect PEF's rate treatment (See Note 16B).

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 adjustment recognized as a component of OCI was a net actuarial gain of $78 million for the year ended December 31, 2006. No amounts related to our OPEB plans were recognized as a component of OCI for the year ended December 31, 2006. The tables below provide a summary of amounts recognized in other comprehensive income for 2008 and 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2008 and 2007. The tables also include 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.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2008	2007	2008	2007
Other comprehensive income (loss)				
Recognized for the year				
Net actuarial loss	$ (64)	$ 24	$ (8)	$ 16
Other, net	(6)	(1)	–	–
Reclassification adjustments				
Net actuarial loss	1	2	–	–
Other, net	1	1	–	–
Regulatory asset (increase) decrease				
Recognized for the year				
Net actuarial (loss) gain	(735)	66	(73)	82
~~Other, net~~	~~(36)~~	~~(8)~~	–	–
Amortized to income				
Net actuarial loss	7	13	1	2
Other, net	1	1	5	4

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2008	2007	2006	2008	2007	2006
Service cost	$ 23	$ 23	$ 22	$ 5	$ 5	$ 4
Interest cost	58	56	52	17	15	17
Expected return on plan assets	(66)	(60)	(59)	(4)	(4)	(4)
Amortization of actuarial loss	6	12	11	–	–	2
Other amortization, net	2	2	1	1	1	1
Net periodic cost	$ 23	$ 33	$ 27	$ 19	$ 17	$ 20

No amounts related to PEC's OPEB plans were recognized as a component of OCI for the year ended December 31, 2006. PEC's pre-tax minimum pension adjustment recognized as a component of OCI for the year ended December 31, 2006, was a net actuarial gain of $59 million. 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 tables below provide a summary of amounts recognized in regulatory assets for 2008 and 2007 and amounts amortized from regulatory assets to net income for 2008 and 2007.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Regulatory asset (increase) decrease				
Recognized for the year				
Net actuarial (loss) gain	**$ (308)**	$ 26	**$ (66)**	$ 82
Other, net	**(31)**	(6)	**–**	–
Amortized to net income				
Net actuarial loss	**6**	12	**–**	–
Other, net	**2**	2	**1**	1

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$ 17**	$ 16	$ 16	**$ 2**	$ 2	$ 3
Interest cost	**53**	52	49	**14**	14	14
Expected return on plan assets	**(90)**	(84)	(78)	**(1)**	(1)	(1)
Amortization of actuarial loss	**1**	1	3	**1**	2	1
Other amortization, net	**(1)**	(1)	(1)	**3**	3	4
Net periodic (benefit) cost	**$ (20)**	$ (16)	$ (11)	**$ 19**	$ 20	$ 21

No amounts related to PEF's OPEB or pension plans were recorded as a component of OCI for the years ended December 31, 2008, 2007 and 2006. 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 tables below provides a summary of amounts recognized in regulatory assets for 2008 and 2007 and amounts amortized from regulatory assets to net income for 2008 and 2007.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Regulatory asset (increase) decrease				
Recognized for the year				
Net actuarial (loss) gain	**$ (427)**	$ 40	**$ (6)**	$ –
Other, net	**(5)**	(1)	**–**	–
Amortized to net income				
Net actuarial loss	**1**	1	**1**	2
Other, net	**(1)**	(1)	**3**	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		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**6.20%**	5.95%	5.65%	**6.20%**	5.95%	5.65%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	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%	**8.10%**	7.70%	8.30%

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 plan 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 2008, 2007 and 2006.

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, 2008 and 2007 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Projected benefit obligation at January 1	**$ 2,142**	$ 2,123	**$ 541**	$ 628
Service cost	**46**	46	**8**	7
Interest cost	**128**	123	**34**	32
Benefit payments	**(127)**	(131)	**(35)**	(30)
Plan amendment	**42**	8	**–**	–
Actuarial loss (gain)	**3**	(27)	**60**	(96)
Obligation at December 31	**2,234**	2,142	**608**	541
Fair value of plan assets at December 31	**1,285**	1,996	**52**	75
Funded status	**$ (949)**	$ (146)	**$ (556)**	$ (466)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $2.234 billion and $463 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $2.196 billion and $422 million at December 31, 2008 and 2007, respectively, and plan assets of $1.285 billion and $269 million at December 31, 2008 and 2007, respectively. The total accumulated benefit obligation for pension plans was $2.196 billion and $2.100 billion at December 31, 2008 and 2007, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Noncurrent assets	$ **–**	$ 48	$ **–**	$ –
Current liabilities	**(10)**	(10)	**(1)**	–
Noncurrent liabilities	**(939)**	(184)	**(555)**	(466)
Funded status	$ **(949)**	$ (146)	$ **(556)**	$ (466)

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)	**2008**	2007	**2008**	2007
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	$ **87**	$ 22	$ **–**	$ (9)
Other, net	**11**	6	**–**	1
Recognized in regulatory assets, net				
Net actuarial loss	**865**	136	**97**	25
Other, net	**62**	28	**18**	23
Total not yet recognized as a component of net periodic cost(a)	$ **1,025**	$ 192	$ **115**	$ 40

(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 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss(a)	$ 48	$ 4
Amortization of other, net(a)	6	5

(a) Adjusted to reflect PEF's rate treatment (See Note 16B)

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Projected benefit obligation at January 1	$ **980**	$ 952	$ **257**	$ 330
Service cost	**23**	23	**5**	5
Interest cost	**58**	56	**17**	15
Plan amendment	**31**	6	**–**	–
Benefit payments	**(55)**	(60)	**(15)**	(12)
Actuarial (gain) loss	**(12)**	3	**48**	(81)
Obligation at December 31	**1,025**	980	**312**	257
Fair value of plan assets at December 31	**521**	805	**22**	44
Funded status	$ **(504)**	$ (175)	$ **(290)**	$ (213)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.025 billion and $980 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $1.021 billion and $974 million at December 31, 2008 and 2007, respectively, and plan assets of $521 million and $805 million at December 31, 2008 and 2007, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Current liabilities	$ **(2)**	$ (2)	$ **–**	$ –
Noncurrent liabilities	**(502)**	(173)	**(290)**	(213)
Funded status	$ **(504)**	$ (175)	$ **(290)**	$ (213)

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)	**2008**	2007	**2008**	2007
Recognized in regulatory assets				
Net actuarial loss (gain)	$ **407**	$ 104	$ **54**	$ (12)
Other, net	**57**	29	**4**	5
Total not yet recognized as a component of net periodic cost	$ **464**	$ 133	$ **58**	$ (7)

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$ 8	$ 3
Amortization of other, net	5	1

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Projected benefit obligation at January 1	$ **881**	$ 880	$ **245**	$ 246
Service cost	**17**	16	**2**	2
Interest cost	**53**	52	**14**	14
Plan amendment	**5**	1	**–**	–
Benefit payments	**(58)**	(57)	**(18)**	(16)
Actuarial loss (gain)	**16**	(11)	**5**	(1)
Obligation at December 31	**914**	881	**248**	245
Fair value of plan assets at December 31	**650**	1,026	**27**	26
Funded status	$ **(264)**	$ 145	$ **(221)**	$ (219)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $914 million and $345 million at December 31, 2008 and 2007, respectively. Those plans had accumulated benefit obligations totaling $884 million and $313 million at December 31, 2008 and 2007, respectively, and plan assets of $650 million and $269 million at December 31, 2008 and 2007, respectively. The total accumulated benefit obligation for pension plans was $884 million and $849 million at December 31, 2008 and 2007, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Noncurrent assets	$ –	$ 221	$ –	$ –
Current liabilities	**(3)**	(3)	–	–
Noncurrent liabilities	**(261)**	(73)	**(221)**	(219)
Funded status	$ **(264)**	$ 145	$ **(221)**	$ (219)

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)	**2008**	2007	**2008**	2007
Recognized in regulatory assets, net				
Net actuarial loss	$ **458**	$ 32	$ **43**	$ 37
Other, net	**5**	(1)	**14**	18
Total not yet recognized as a component of net periodic cost	$ **463**	$ 31	$ **57**	$ 55

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2009.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$ 36	$ 2
Amortization of other, net	–	4

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	**2008**	2007
Discount rate	**6.30%**	6.20%	**6.20%**	6.20%
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	**–**	–	**2016**	2015

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	$ 3	$ 2	$ 1
Effect on postretirement benefit obligation	37	19	15
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(30)	(16)	(12)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2008 include contributions directly to pension plan assets of $33 million, $24 million and less than $1 million, respectively, and 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, 25 percent for PEC and 15 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2008 and 2007, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

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

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Fair value of plan assets at January 1	**$ 1,996**	$ 1,836	**$ 75**	$ 74
Actual return on plan assets	**(627)**	219	**(16)**	7
Benefit payments	**(127)**	(131)	**(35)**	(30)
Employer contributions	**43**	72	**28**	24
Fair value of plan assets at December 31	**$ 1,285**	$ 1,996	**$ 52**	$ 75

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Fair value of plan assets at January 1	**$ 805**	$ 741	**$ 44**	$ 45
Actual return on plan assets	**(255)**	89	**(14)**	5
Benefit payments	**(55)**	(60)	**(15)**	(12)
Employer contributions	**26**	35	**7**	6
Fair value of plan assets at December 31	**$ 521**	$ 805	**$ 22**	$ 44

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2008**	2007	**2008**	2007
Fair value of plan assets at January 1	**$ 1,026**	$ 952	**$ 26**	$ 24
Actual return on plan assets	**(321)**	113	**–**	1
Benefit payments	**(58)**	(57)	**(18)**	(16)
Employer contributions	**3**	18	**19**	17
Fair value of plan assets at December 31	**$ 650**	$ 1,026	**$ 27**	$ 26

The asset allocation for the benefit plans at the end of 2008 and 2007 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	2009	**2008**	2007
Equity – domestic	40%	**39%**	42%
Equity – international	20%	**20%**	25%
Debt – domestic	10%	**10%**	11%
Debt – international	15%	**16%**	12%
Other	15%	**15%**	10%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2009	**2008**	2007
Equity – domestic	20%	**18%**	28%
Equity – international	10%	**10%**	16%
Debt – domestic	50%	**57%**	41%
Debt – international	10%	**8%**	8%
Other	10%	**7%**	7%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2009	**2008**	2007
Equity – domestic	40%	**39%**	42%
Equity – international	20%	**20%**	25%
Debt – domestic	10%	**10%**	11%
Debt – international	15%	**16%**	12%
Other	15%	**15%**	10%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2009	**2008**	2007
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 2009, we expect to make at least \$130 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$154, \$157, \$158, \$167, \$169 and \$923, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$40, \$43, \$45, \$48, \$50 and \$268, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$4, \$4, \$5, \$5, \$6 and \$40, respectively.

In 2009, PEC expects to make at least \$75 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$78, \$79, \$79, \$83, \$82 and \$445, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$17, \$19, \$21, \$23, \$24, and \$139, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$2, \$2, \$2, \$3, \$3 and \$21, respectively.

In 2009, PEF expects to make at least \$55 million in 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$58, \$59, \$60, \$62, \$63 and \$354, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$20, \$21, \$21, \$22, \$22 and \$109, 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 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately \$2, \$2, \$2, \$2, \$3 and \$16, 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 and financial reviews using a combination of financial analysis and 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, 2008 and 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 physical commodity contracts are not derivatives 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, 2008 and 2007, the remaining liability was $7 million and $10 million, respectively.

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary, PVI, sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. 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 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 5). We had a $108 million cash collateral liability related to these contracts at December 31, 2007, included in other current liabilities on the Consolidated Balance Sheet. As discussed in Note 3A, 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.

Due to the divestitures of Gas and CCO, 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 in 2006. For the year ended December 31, 2006, discontinued operations, net of tax on the Consolidated Statements of Income included $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges, and immaterial net gains and losses from other derivative instruments related to Gas and CCO.

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. Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. 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. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2008 and 2007, PEC recorded a net realized gain of $2 million and a net realized loss of $9 million, respectively. PEC's net realized loss was not material during the year ended December 31, 2006. During the years ended December 31, 2008, 2007 and 2006, PEF recorded a net realized gain of $172 million, a net realized loss of $46 million and a net realized gain of $39 million, respectively.

At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in other liabilities and deferred credits on the PEC Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was 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 position included in derivative liabilities on the PEC Consolidated Balance Sheet. Certain counterparties have held cash collateral with PEC in support of these instruments. PEC had an $18 million cash collateral asset included in prepayments and other current assets on the PEC Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in current derivative assets, a $1 million long-term derivative asset position included in derivative assets, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as an $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 derivative liability position included in current derivative liabilities, and a $9 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. Certain counterparties have posted or held cash collateral in support of these instruments. PEF had a $335 million cash collateral asset included in derivative collateral posted and a $12 million cash collateral liability included in other current liabilities on the PEF Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding some of 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2008 and 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 2008, 2007 and 2006.

At December 31, 2008 and 2007, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

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)	2008	2007	2008	2007	2008	2007
Fair value of liabilities	$ (65)	$ (12)	$ (35)	$ (12)	$ –	$ –

The effective portion of gains and losses from interest rate cash flow hedges, including terminated hedges, is recorded in accumulated other comprehensive income, and amortized to net interest charges as the hedged transactions occur. The ineffective portion of interest rate cash flow hedges was not material to our or the Utilities' results of operations for 2008, 2007 and 2006.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 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)	$ (56)	$ (35)	$ –
Portion expected to be reclassified to earnings during the next 12 months(b)	$ (3)	$ (2)	$ –

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

At December 31, 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, 2008, the Parent had $200 million notional of interest rate cash flow hedges. During 2008, the Parent entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In January 2009, the Parent entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

At December 31, 2008 and 2007, PEC had $250 million notional and $200 million notional, respectively, of interest rate cash flow hedges. In March 2008, all of PEC's 2007 forward starting swaps were terminated in conjunction with PEC's issuance of $325 million of First Mortgage Bonds, 6.30% Series due 2038. During 2008, PEC entered into a combined $250 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. All of PEC's 2008 forward starting swaps were terminated on January 12, 2009, in conjunction with PEC's issuance of $600 million of First Mortgage Bonds, 5.30% Series due 2019. After the January 2009 debt issuance, PEC entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

At December 31, 2008 and 2007, PEF had no outstanding interest rate cash flow hedge positions. During 2008, PEF entered into a combined $550 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In June 2008, all of PEF's forward starting swaps were terminated in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. In January 2009, PEF entered into a $50 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, 2008 and 2007, neither we nor the Utilities had any outstanding positions in such contracts.

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, 2008, the Parent had issued $386 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 the Public Utility Holding Company Act of 1935 (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 2008, 2007 and 2006 to PEC amounted to $194 million, $182 million and $188 million, respectively, and services provided to PEF were $160 million, $174 million and $165 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2008, 2007 and 2006 amounted to $44 million, $54 million and $34 million, respectively. Services provided by PEF to PEC during 2008, 2007 and 2006 amounted to $12 million, $10 million and $8 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 3.29%, 5.49% and 5.17% at December 31, 2008, 2007 and 2006, 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. 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 and $321 million for the years ended December 31, 2007 and 2006, 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.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for 2007 and 2006 transactions between PEF and businesses included in the Corporate and Other segment, which are at rates set by the FPSC. In accordance with SFAS No 71, profits on intercompany sales between PEF and businesses included in the Corporate and Other 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 and 2006 were not significant.

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, 2008					
Revenues					
Unaffiliated	$ 4,429	$ 4,730	$ 8	$ –	$ 9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Segment profit (loss)	531	383	(141)	–	773
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560

(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, amortization and accretion	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	11,955	10,063	16,356	(12,088)	26,286
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, amortization and accretion	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	11,999	8,648	15,394	(11,266)	24,775
Capital and investment expenditures	808	741	12	(9)	1,552

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. 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)	2008	2007	2006
OTHER INCOME			
Nonregulated energy and delivery services income	$ 38	$ 36	$ 41
DIG Issue C20 amortization (Note 17A)	3	4	5
Gain on sale of Level 3 Communications, Inc. stock (a)	–	–	32
Investment gains, net	–	5	4
Income from equity investments, net	1	–	–
Reversal of indemnification liability (Note 21B)	–	–	29
Other, net	3	–	–
Total other income	45	45	111
OTHER EXPENSE			
Nonregulated energy and delivery services expenses	21	24	27
Donations	25	22	20
Contingent value obligation unrealized loss, net (Note 15)	–	2	25
Investment losses, net	13	–	–
Loss from equity investments, net	–	3	2
Loss on debt redemption(b)	–	–	59
Derivative mark-to-market losses, net	3	–	–
Indemnification liability (Note 21B)	–	–	13
Other, net	–	1	2
Total other expense	62	52	148
Other, net – Progress Energy	$ (17)	$ (7)	$ (37)

PEC

(in millions)	2008	2007	2006
OTHER INCOME			
Nonregulated energy and delivery services income	$ 20	$ 14	$ 15
DIG Issue C20 amortization (Note 17A)	3	4	5
Investment gains, net	–	1	–
Reversal of indemnification liability (Note 21B)	–	–	29
Other, net	8	4	3
Total other income	31	23	52
OTHER EXPENSE			
Nonregulated energy and delivery services expenses	9	8	7
Donations	14	9	10
Losses from equity investments, net	1	–	1
Derivative mark-to-market losses	3	–	–
Indemnification liability (Note 21B)	–	–	13
Total other expense	27	17	31
Other, net – PEC	$ 4	$ 6	$ 21

PEF

(in millions)		2008		2007		2006
OTHER INCOME						
Nonregulated energy and delivery services income	$	**20**	$	24	$	26
Investment gains, net		–		2		2
Other, net		**2**		–		–
Total other income		**22**		26		28
OTHER EXPENSE						
Nonregulated energy and delivery services expenses		**12**		16		20
Donations		**11**		8		10
Investment losses, net		**9**		–		–
Losses from equity investments, net		–		1		1
Other, net		–		3		1
Total other expense		**32**		28		32
Other, net – PEF	$	**(10)**	$	(2)	$	(4)

(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 Communications, Inc. stock received as part of the sale of our interest in PT LLC (See Note 3F). 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 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 potential and pending claims cannot be predicted. 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)	2008	2007
PEC		
MGP and other sites(a)	$ 16	$ 16
PEF		
Remediation of distribution and substation transformers	22	31
MGP and other sites	15	17
Total PEF environmental remediation accruals(b)	37	48
Total Progress Energy environmental remediation accruals	$ 53	$ 64

(a)Expected to be paid out over one to five years.
(b)Expected to be paid out over one to 15 years.

PROGRESS ENERGY

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

In 2006, the NCUC and the SCPSC authorized PEC to defer and amortize certain environmental remediation expenses. Remediation expenses not authorized to be deferred are included in operation and maintenance expense.

Including the Ward Transformer site located in Raleigh, N.C. (Ward), and MGP sites discussed below, for the year ended December 31, 2008, PEC accrued approximately $8 million, of which $2 million was deferred, and spent approximately $8 million. These amounts primarily relate to the Ward site. For the year ended December 31, 2007, including the Carolina Transformer site, the Ward 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. The 2006 accrual included $12 million for the minimum estimated total remediation cost for all of PEC's remaining MGP sites 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.

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 site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced, on an interim basis, PEC's proportionate responsibility for funding the remediation. During 2008, PEC increased its accrual due to an increase in the estimated scope of work. At December 31, 2008 and 2007, PEC's recorded liability for the site was approximately $7 million and $6 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed a complaint seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. The complaint names 28 parties that did not sign a tolling agreement with PEC, which was entered into by over 200 PRPs. The tolling agreement suspends the running of the statute of limitations for determination of cost recovery from PRPs at the Ward site. The litigation has been stayed to allow the parties to explore private settlements. The outcome of these matters cannot be predicted.

On September 30, 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for the operable unit for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On January 19, 2009, PEC and several of the other participating PRPs at the Ward site submitted a letter containing a good faith response to the EPA's September 30, 2008 letter. Another group of PRPs separately submitted a good faith response to the EPA's September 30, 2008 letter. Although a loss is considered probable, an agreement among the PRPs for these matters has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation for Ward OU1 and Ward OU2.

PEF

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. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution operations and maintenance expense (O&M) costs will not be recoverable through the ECRC. Based on historical experience, PEF projects costs will be between approximately $3 million and $4 million per year. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. 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, 2008 and 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 previous table, 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, 2008, PEF made no accruals and spent approximately $2 million. 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

At December 31, 2008 and 2007, we were 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 included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), 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 December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were \$1.859 billion, including \$1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and \$847 million at PEF, which related entirely to in-process CAIR projects. At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were \$1.225 billion, including \$902 million at PEC and \$323 million at PEF. PEC completed installation of controls to meet the requirements of the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) in 2007.

PEF participated in a coalition of Florida utilities that filed a challenge to the CAIR as it applied to Florida. PEF withdrew from the coalition during the fourth quarter of 2008. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, including the Florida challenge, which vacated the CAIR in its entirety. On September 24, 2008, petitions for rehearing were filed by a number of parties. On December 23, 2008, the D.C. Court of Appeals remanded the case without vacating the CAIR for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. The Court's December 23, 2008 decision remanding the CAIR maintained its current implementation such that CAIR satisfies best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Depending on whether this determination continues to be maintained as the CAIR is revised, for BART-eligible units CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions. As a result, BART for SO_2 and NOx could apply to PEC's and PEF's BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). On September 17, 2008, the Utility Air Regulatory Group filed a petition for writ of certiorari with the U.S. Supreme Court seeking a review of the decision that vacated the CAMR. On October 17, 2008, the EPA filed a similar petition and subsequently withdrew it on January 29, 2009. The Utility Air Regulatory Group's petition for writ of certiorari was denied on February 23, 2009. 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 any review granted by the Supreme Court will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

PEF is continuing construction of its in-process emission control projects. On December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and complete construction of its emission control projects at CR 4 and CR 5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which is anticipated to be around 2020.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. At December 31, 2008, PEC had approximately \$22 million in SO_2 emission allowances, which will be utilized to comply with existing Clean Air Act requirements, and an immaterial amount of NOx emission allowances. In order to achieve compliance with the requirements of the CAIR pursuant to its Integrated Clean Air Compliance Plan, PEF needed to purchase CAIR seasonal and annual NOx allowances. On November 12, 2008, the FPSC approved PEF's petition for recovery of its CAIR expenses, including NOx allowance inventory expense, through the ECRC. At December 31, 2008, PEF had approximately \$59 million in annual NOx emission allowance inventory, \$6 million in seasonal NOx emission allowance inventory and approximately \$11 million in SO_2 emission allowance inventory. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements.

As discussed in Note 7B, 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, in 2005 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, 2008 and 2007, the amount of the liability was $10 million and $30 million, respectively, based upon the respective estimates for the remaining Clean Smokestacks Act compliance costs. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 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. On November 2, 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part the Clean Smokestacks amortization, and subsequently reclassified $29 million of indemnification expense to Clean Smokestacks amortization. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service (See Note 7B).

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2008, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$ 3,186	$ 2,532	$ 1,938	$ 1,532	$ 1,167	$ 6,669
Purchased power	422	432	447	436	419	3,477
Construction obligations	1,098	1,458	1,532	1,433	1,511	2,418
Other purchase obligations	53	68	40	33	24	168
Total	$ 4,759	$ 4,490	$ 3,957	$ 3,434	$ 3,121	$ 12,732

PEC

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$ 1,619	$ 1,272	$ 832	$ 596	$ 561	$ 1,593
Purchased power	87	92	99	85	78	598
Construction obligations	182	72	16	–	2	–
Other purchase obligations	7	3	3	3	3	6
Total	$ 1,895	$ 1,439	$ 950	$ 684	$ 644	$ 2,197

PEF

(in millions)	2009	2010	2011	2012	2013	Thereafter
Fuel	$ 1,567	$ 1,260	$ 1,106	$ 936	$ 606	$ 5,076
Purchased power	335	340	348	351	341	2,879
Construction obligations	916	1,386	1,516	1,433	1,509	2,418
Other purchase obligations	36	30	36	29	21	162
Total	$ 2,854	$ 3,016	$ 3,006	$ 2,749	$ 2,477	$ 10,535

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.078 billion, $2.360 billion and $1.628 billion for 2008, 2007 and 2006, respectively. PEC's total payments under these commitments for its generating plants were $1.446 billion, $1.049 billion and $1.051 billion in 2008, 2007 and 2006, respectively. PEF's payments totaled $1.632 billion, $1.311 billion and $577 million in 2008, 2007 and 2006, respectively.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units (See discussion under Construction Obligations below.) This $355 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2009 to 2028. 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 (19 percent of net output) of capacity through 2009 with an estimated remaining 2009 payment of approximately $29 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $90 million, $77 million and $80 million for 2008, 2007 and 2006, respectively.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $25 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $26 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $44 million, $39 million and $45 million in 2008, 2007 and 2006, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $16 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2028. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $55 million, $95 million and $182 million in 2008, 2007 and 2006, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (19 percent of net output) of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $178 million, $161 million and $162 million for 2008, 2007 and 2006, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million, $65 million, $56 million, $48 million and $42 million for 2009 through 2013, respectively, and $102 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 786 MW of firm capacity with expiration dates ranging from 2009 to 2025. 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 net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $273 million, $288 million and $277 million for 2008, 2007 and 2006, respectively. At December 31, 2008, minimum expected future capacity payments under these contracts were $263 million, $267 million, $281 million, $292 million and $288 million for 2009 through 2013, respectively, and $2.751 billion payable 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 June 2008, PEC entered into a conditional contract with an interstate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from May 2011 through April 2031. The estimated total cost to PEC associated with this agreement is approximately $487 million. The transaction is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. 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 2008, PEC entered into an amendment to an existing transportation service agreement with an intrastate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through May 2030. The total additional cost to PEC associated with this amendment is estimated to be approximately $54 million. The amendment is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related intrastate natural gas pipeline system expansions and other contractual provisions. 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 April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.086 billion. The contracts are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. In addition to the FGT contracts, during 2008, PEF entered into additional gas supply and transportation arrangements for the period from 2010 through 2025 that are subject to certain conditions. The total current notional cost of these additional agreements is estimated to be approximately $849 million. 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 $1.018 billion, $698 million and $387 million for 2008, 2007 and 2006, respectively.

PEC has purchase obligations related to various capital projects including new generation, transmission and obligations related to the Clean Smokestacks Act. Total payments under PEC's construction-related contracts were $140 million, $208 million and $233 million for 2008, 2007 and 2006, respectively. PEC's future obligations under these contracts are $182 million, $72 million, $16 million and $1 million for 2009, 2010, 2011 and 2013, respectively. PEC has no future obligation under these contracts for 2012.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.736 billion are included for the multi-year contract and do not assume any joint ownership. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. See Note 7C for additional information about the Levy project. In 2008, PEF made payments of $117 million toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $761 million, $490 million and $154 million for 2008, 2007 and 2006, 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 PEF service agreements related to the Hines Energy Complex and the Bartow plant. Our payments under these agreements were $110 million, $75 million and $100 million for 2008, 2007 and 2006, respectively.

PEC has various purchase obligations for emission obligations, limestone supply and fleet vehicles. Total purchases under these contracts were $36 million, $25 million and $51 million for 2008, 2007 and 2006, respectively. Future obligations under these contracts are $7 million for 2009, $3 million each for 2010 through 2013 and $6 million thereafter.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow plant, emission obligations and fleet vehicles. Total payments under these contracts were $58 million, $24 million and $19 million for 2008, 2007 and 2006, respectively. Future obligations are primarily comprised of the long-term service agreements. These agreements total $31 million, $29 million, $36 million, $29 million and $21 million for 2009 through 2013, respectively, with approximately $162 million payable thereafter.

B. LEASES

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $38 million, $40 million and $42 million for 2008, 2007 and 2006, respectively. Our purchased power expense under agreements classified as operating leases was approximately $152 million, $69 million and $60 million in 2008, 2007 and 2006, respectively.

PEC's rent expense under operating leases totaled $26 million, $23 million and $25 million during 2008, 2007 and 2006, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million, $6 million and $8 million for 2008, 2007 and 2006, respectively. Purchased power expense under agreements classified as operating leases was approximately $9 million, $10 million and $10 million in 2008, 2007 and 2006, respectively.

PEF's rent expense under operating leases totaled $11 million, $15 million and $16 million during 2008, 2007 and 2006, respectively. These amounts include rent expense allocated from PESC to PEF of $3 million, $6 million and $7 million for 2008, 2007 and 2006, respectively. Purchased power expense under agreements classified as operating leases was approximately $142 million, $59 million and $49 million in 2008, 2007 and 2006, respectively.

Assets recorded under capital leases, including plant related to purchased power agreements, at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Buildings	**$ 267**	$ 267	**$ 30**	$ 30	**$ 237**	$ 237
Less: Accumulated amortization	**(28)**	(20)	**(14)**	(13)	**(14)**	(7)
Total	**$ 239**	$ 247	**$ 16**	$ 17	**$ 223**	$ 230

At December 31, 2008, 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
2009	$ 29	$ 48	$ 3	$ 37	$ 26	$ 7
2010	28	29	2	21	26	5
2011	28	23	2	16	26	4
2012	28	38	2	13	26	22
2013	36	64	10	31	26	31
Thereafter	272	955	–	559	272	394
Minimum annual payments	421	$ 1,157	19	$ 677	402	$ 463
Less amount representing imputed interest	(182)		(3)		(179)	
Present value of net minimum lease payments under capital leases	$ 239		$ 16		$ 223	

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 2008, PEC entered into a 336-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for an initial minimum payment of approximately $18 million in 2013, with minimum annual payments escalating at a rate of 2.5 percent through 2032, for a total of approximately $460 million.

In 2007, PEF entered into a 632-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from June 2012 through May 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 minimum 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 a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 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 116.6-MW (100 percent of net output) purchased power, which is classified as a capital lease of the related plant. 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 $7 million from 2012 through November 2036, for a total of approximately $170 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, $6 million, $5 million, $2 million and $1 million for 2009 through 2013, respectively. Rents received under these operating leases totaled $9 million, $8 million and $9 million for 2008, 2007 and 2006, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2009 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million each for 2008 and 2007 and $31 million for 2006. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $81 million, $78 million and $72 million for 2008, 2007 and 2006, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2009 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, 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 Consolidated Balance Sheets.

At December 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 21B). PEC's maximum exposure cannot be determined. At December 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 December 31, 2008 and 2007, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $61 million and $80 million, respectively. These amounts included $10 million and $30 million, respectively, for PEC and $8 million for PEF at December 31, 2008 and 2007. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 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 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. 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 damage claims as they incur additional costs.

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States

Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. 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. However, the Utilities cannot predict the outcome of this matter.

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); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was 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 previously 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 are 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 June 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.

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 annual 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, 2008, 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 11B, 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 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 Non-guarantor Subsidiary column includes the consolidated financial results of our wholly owned subsidiary PEC. The Other column includes the consolidated financial results of all other non-guarantor subsidiaries, and elimination entries for all intercompany transactions. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-K. 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.

Condensed Consolidating Statement of Income
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$ –	$ 4,738	$ 4,429	$ –	$ 9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,030	(26)	1,820
Depreciation, amortization and accretion	–	306	518	15	839
Taxes other than on income	–	309	198	1	508
Other	–	1	(5)	1	(3)
Total operating expenses	3	4,057	3,433	(9)	7,484
Operating (loss) income	(3)	681	996	9	1,683
Other income (expense)					
Interest income	11	9	12	(8)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	4	(3)	(17)
Total other income (expense), net	11	86	43	(11)	129
Interest charges					
Interest charges	201	263	219	(4)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	207	(4)	639
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(193)	532	832	2	1,173
Income tax (benefit) expense	(85)	172	298	10	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Minority interest in subsidiaries' income, net of tax	–	(5)	–	–	(5)
Income (loss) from continuing operations	833	355	534	(949)	773
Discontinued operations, net of tax	(3)	60	–	–	57
Net income (loss)	$ 830	$ 415	$ 534	$ (949)	$ 830

Condensed Consolidating Statement of Income
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$ –	$ 4,768	$ 4,385	$ –	$ 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	1,024	(26)	1,842
Depreciation, amortization and accretion	–	369	519	17	905
Taxes other than on income	–	309	192	–	501
Other	–	20	(2)	12	30
Total operating expenses	10	4,178	3,416	3	7,607
Operating (loss) income	(10)	590	969	(3)	1,546
Other income (expense)					
Interest income	27	8	21	(22)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	6	(11)	(7)
Total other income (expense), net	27	47	37	(33)	78
Interest charges					
Interest charges	203	210	215	(23)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	210	(23)	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	439	796	(13)	1,036
Income tax (benefit) expense	(79)	117	295	1	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	313	501	(610)	693
Discontinued operations, net of tax	15	30	–	(234)	(189)
Net income (loss)	$ 504	$ 343	$ 501	$ (844)	$ 504

Condensed Consolidating Statement of Income
Year Ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$ –	$ 4,637	$ 4,086	$ 1	$ 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	930	(45)	1,583
Depreciation, amortization and accretion	–	406	571	34	1,011
Taxes other than on income	–	309	191	–	500
Other	–	21	–	14	35
Total operating expenses	14	4,021	3,199	3	7,237
Operating (loss) income	(14)	616	887	(2)	1,487
Other income (expense)					
Interest income	47	15	25	(28)	59
Allowance for equity funds used during construction	–	17	4	–	21
Other, net	(80)	23	21	(1)	(37)
Total other (expense) income, net	(33)	55	50	(29)	43
Interest charges					
Interest charges	276	187	217	(49)	631
Allowance for borrowed funds used during construction	–	(5)	(2)	–	(7)
Total interest charges, net	276	182	215	(49)	624
(Loss) income from continuing operations before income tax, *equity in earnings of consolidated subsidiaries* and minority interest	(323)	489	722	18	906
Income tax (benefit) expense	(123)	174	265	23	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	299	457	(784)	551
Discontinued operations, net of tax	(8)	400	–	(372)	20
Net income (loss)	$ 571	$ 699	$ 457	$(1,156)	$ 571

Condensed Consolidating Balance Sheet
December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ –	$ 8,790	$ 9,385	$ 118	$ 18,293
Current assets					
Cash and cash equivalents	88	73	18	1	180
Receivables, net	–	363	502	2	867
Notes receivable from affiliated companies	34	44	55	(133)	–
Inventory	–	606	633	–	1,239
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Prepayments and other current assets	48	169	137	(6)	348
Total current assets	170	1,916	1,570	(136)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Nuclear decommissioning trust funds	–	417	672	–	1,089
Goodwill	–	–	–	3,655	3,655
Other assets and deferred debits	155	196	295	103	749
Total deferred debits and other assets	12,079	1,937	2,210	(8,166)	8,060
Total assets	$12,249	$ 12,643	$ 13,165	$ (8,184)	$ 29,873
CAPITALIZATION AND LIABILITIES					
Capitalization					
Common stock equity	$ 8,687	$ 3,519	$ 4,301	$ (7,820)	$ 8,687
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	–	93
Minority interest	–	3	–	3	6
Long-term debt, affiliate	–	309	–	(37)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	7,869	(7,854)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	–	(206)	–
Derivative liabilities	31	380	82	–	493
Other current liabilities	220	964	773	(14)	1,943
Total current liabilities	820	1,921	965	(220)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Accrued pension and other benefits	10	540	856	188	1,594
Other liabilities and deferred credits	35	941	1,377	(4)	2,349
Total deferred credits and other liabilities	46	2,675	4,331	(110)	6,942
Total capitalization and liabilities	$12,249	$ 12,643	$ 13,165	$ (8,184)	$ 29,873

Condensed Consolidating Balance Sheet
December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ –	$ 7,600	$ 8,880	$ 125	$ 16,605
Current assets					
Cash and cash equivalents	185	43	25	2	255
Receivables, net	–	574	446	102	1,122
Notes receivable from affiliated companies	157	149	–	(306)	–
Inventory	–	484	510	–	994
Regulatory assets	–	6	148	–	154
Assets to be divested	–	48	–	4	52
Prepayments and other current assets	21	188	110	(94)	225
Total current assets	363	1,492	1,239	(292)	2,802
Deferred debits and other assets					
Investment in consolidated subsidiaries	10,942	–	–	(10,942)	–
Regulatory assets	–	266	680	–	946
Nuclear decommissioning trust funds	–	580	804	–	1,384
Goodwill	–	1	–	3,654	3,655
Other assets and deferred debits	149	729	352	(284)	946
Total deferred debits and other assets	11,091	1,576	1,836	(7,572)	6,931
Total assets	$11,454	$ 10,668	$ 11,955	$ (7,739)	$ 26,338
CAPITALIZATION AND LIABILITIES					
Common stock equity	$ 8,395	$ 3,052	$ 3,752	$ (6,804)	$ 8,395
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	10,992	6,162	6,994	(6,839)	17,309
Current liabilities					
Current portion of long-term debt	–	577	300	–	877
Short-term debt	201	–	–	–	201
Notes payable to affiliated companies	–	227	154	(381)	–
Derivative liabilities	–	38	19	–	57
Liabilities to be divested	–	8	–	–	8
Other current liabilities	215	1,199	697	48	2,159
Total current liabilities	416	2,049	1,170	(333)	3,302
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	59	936	(634)	361
Regulatory liabilities	–	1,330	1,098	126	2,554
Accrued pension and other benefits	12	347	459	(55)	763
Other liabilities and deferred credits	34	721	1,298	(4)	2,049
Total deferred credits and other liabilities	46	2,457	3,791	(567)	5,727
Total capitalization and liabilities	$11,454	$ 10,668	$ 11,955	$ (7,739)	$ 26,338

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$ (90)	$ 221	$ 1,061	$ 26	$ 1,218
Investing activities					
Gross property additions	–	(1,553)	(760)	(20)	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	8	5	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(682)	(118)	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	626	120	1,534
Changes in advances to affiliated companies	123	105	(55)	(173)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Other investing activities	20	8	–	(30)	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,042)	(127)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to minority interests of consolidated subsidiaries	–	(85)	–	–	(85)
Changes in advances from affiliated companies	–	(21)	(154)	175	–
Contributions from parent	–	85	15	(100)	–
Other financing activities	–	1	(19)	(8)	(26)
Net cash (used) provided by financing activities	(42)	1,216	(26)	100	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(7)	(1)	(75)
Cash and cash equivalents at beginning of year	185	43	25	2	255

Cash and cash equivalents at end of year	$	88	$	73	$	18	$	1	$	180

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$ 76	$ 489	$ 1,018	$ (331)	$ 1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	10	614	675
Purchases of available-for-sale securities and other investments	–	(640)	(603)	(170)	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	622	169	1,452
Changes in advances to affiliated companies	(99)	(112)	24	187	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(4)	33	30
Net cash provided (used) by investing activities	231	(1,291)	(892)	495	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(143)	153	–
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)
Cash distributions to minority interests of consolidated subsidiaries	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	154	(305)	–
Contributions from parent	–	10	21	(31)	–
Other financing activities	–	49	(4)	20	65
Net cash (used) provided by financing activities	(275)	805	(172)	(163)	195
Net increase (decrease) in cash and cash equivalents	32	3	(46)	1	(10)
Cash and cash equivalents at beginning of year	153	40	71	1	265
Cash and cash equivalents at end of year	$ 185	$ 43	$ 25	$ 2	$ 255

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$ 1,295	$ 1,110	$ 1,094	$(1,498)	$ 2,001
Investing activities					
Gross property additions	–	(865)	(705)	(2)	(1,572)
Nuclear fuel additions	–	(12)	(102)	–	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	5	410	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(896)	(12)	(2,452)
Proceeds from available-for-sale securities and other investments	898	724	1,006	3	2,631
Changes in advances to affiliated companies	409	(39)	(24)	(346)	–
Proceeds from repayment of long-term affiliate debt	131	–	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	–	(287)	–
Other investing activities	(63)	(6)	(6)	52	(23)
Net cash provided (used) by investing activities	743	419	(722)	(313)	127
Financing activities					
Issuance of common stock	185	–	–	–	185
Dividends paid on common stock	(607)	–	–	–	(607)
Dividends paid to parent	–	(1,135)	(339)	1,474	–
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	–
Cash distributions to minority interests of consolidated subsidiaries	–	(79)	–	–	(79)
Changes in advances from affiliated companies	–	(243)	(11)	254	–
Contributions from parent	–	67	–	(67)	–
Other financing activities	(8)	4	(3)	18	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	(426)	1,810	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(54)	(1)	(340)
Cash and cash equivalents at beginning of year	239	239	125	2	605
Cash and cash equivalents at end of year	$ 153	$ 40	$ 71	$ 1	$ 265

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2008				
Operating revenues	**$ 2,066**	**$ 2,244**	**$ 2,696**	**$ 2,161**
Operating income	**365**	**406**	**591**	**321**
Income from continuing operations	**149**	**200**	**308**	**116**
Net income	**209**	**205**	**309**	**107**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.58**	**0.77**	**1.18**	**0.44**
Net income	**0.81**	**0.79**	**1.19**	**0.41**
Diluted earnings per common share				
Income from continuing operations	**0.58**	**0.77**	**1.18**	**0.44**
Net income	**0.81**	**0.79**	**1.18**	**0.41**
Dividends declared per common share	**0.615**	**0.615**	**0.615**	**0.620**
Market price per share – High	**49.16**	**43.58**	**45.52**	**45.60**
– Low	**40.54**	**41.00**	**40.11**	**32.60**
2007				
Operating revenues	$ 2,072	$ 2,129	$ 2,750	$ 2,202
Operating income	351	301	610	284
Income from continuing operations	149	138	311	95
Net income (loss)	275	(193)	319	103
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
Net income (loss)	1.08	(0.75)	1.24	0.40
Diluted earnings per common share				
Income from continuing operations	0.59	0.54	1.21	0.37
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

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.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2008				
Operating revenues	**$ 1,068**	**$ 1,048**	**$ 1,266**	**$ 1,047**
Operating income	**240**	**205**	**353**	**198**
Net income	**123**	**104**	**201**	**106**
2007				
Operating revenues	$ 1,058	$ 996	$ 1,286	$ 1,045
Operating income	235	180	375	179
Net income	124	88	204	85

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
2008				
Operating revenues	**$ 996**	**$ 1,194**	**$ 1,428**	**$ 1,113**
Operating income	**122**	**198**	**236**	**124**
Net income	**67**	**125**	**143**	**50**
2007				
Operating revenues	$ 1,011	$ 1,129	$ 1,456	$ 1,153
Operating income	117	125	235	109
Net income	61	68	138	50

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.

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, 2008. 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, 2008, 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, 2008, 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, 2008, 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, 2008, 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, 2008, 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 and consolidated financial statement schedule as of and for the year ended December 31, 2008, of the Company and our report dated March 2, 2009, expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule and included an explanatory paragraph regarding the adoption of a new accounting principle.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

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, 2008. 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, 2008, PEC maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEC's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEC's independent 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, 2008 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, 2008. 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, 2008, PEF maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEF's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEF's independent 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, 2008 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's directors is set forth in Progress Energy's definitive proxy statement for the 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 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 Progress Energy 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.

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. Non-audit services that are specifically prohibited under Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting

Oversight Board rules are specifically prohibited under the policy. Prior to the approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the services, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between Progress Energy and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than Progress Energy) with respect to the promoting, marketing or recommending or a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte. 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 2009 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

	2008	2007
Audit fees	$ **1,769,000**	$ 1,576,000
Audit-related fees	**51,000**	21,000
Tax fees	**4,000**	248,000
Total	$ **1,824,000**	$ 1,845,000

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) accounting consultations arising as part of the audits and (v) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions.

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.

The Audit Committee has concluded that the provision of the nonaudit services listed above as Tax 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:

Consolidated Financial Statement Schedules for the Years Ended December 31, 2008, 2007 and 2006:

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.

3. Exhibits Filed:

See *EXHIBIT INDEX*

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 on the balance sheet from the related assets:					
DECEMBER 31, 2008					
Uncollectible accounts	**$ 29**	**$ 24**	**$ –**	**$ (35)**	**$ 18**
Fossil fuel plants dismantlement reserve	**144**	**1**	**–**	**–**	**145**
Nuclear refueling outage reserve	**2**	**12**	**–**	**–**	**14**
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

(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.

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 on the balance sheet from the related assets:					
DECEMBER 31, 2008					
Uncollectible accounts	**$ 6**	**$ 10**	**$ –**	**$ (10)**	**$ 6**
DECEMBER 31, 2007					
Uncollectible accounts	$ 5	$ 10	$ 2	$ (11)	$ 6
DECEMBER 31, 2006					
Uncollectible accounts	$ 4	$ 9	$ –	$ (8)	$ 5

(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.

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 on the balance sheet from the related assets:					
DECEMBER 31, 2008					
Uncollectible accounts	**$ 10**	**$ 14**	**$ 1**	**$ (14)**	**$ 11**
Fossil fuel plants dismantlement reserve	**144**	**1**	**–**	**–**	**145**
Nuclear refueling outage reserve	**2**	**12**	**–**	**–**	**14**
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

(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.

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.

Date: March 2, 2009

PROGRESS ENERGY, INC.
(Registrant)

By: /s/ William D. Johnson
(William D. Johnson)
Chairman, President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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	March 2, 2009
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	March 2, 2009
/s/ David L. Burner (David L. Burner)	Director	March 2, 2009
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	March 2, 2009
/s/ James B. Hyler, Jr. (James B. Hyler, Jr.)	Director	March 2, 2009
/s/ Robert W. Jones (Robert W. Jones)	Director	March 2, 2009
/s/ W. Steven Jones (W. Steven Jones)	Director	March 2, 2009
/s/ E. Marie McKee (E. Marie McKee)	Director	March 2, 2009
/s/ John H. Mullin, III (John H. Mullin, III)	Director	March 2, 2009

/s/ Charles W. Pryor, Jr. (Charles W. Pryor, Jr.)	Director	March 2, 2009
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	March 2, 2009
/s/ Theresa M. Stone (Theresa M. Stone)	Director	March 2, 2009
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	March 2, 2009

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.

Date: March 2, 2009

CAROLINA POWER & LIGHT COMPANY
(Registrant)

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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	March 2, 2009
/s/ Jeffrey A. Corbett (Jeffrey A. Corbett)	Director	March 2, 2009
/s/ John R. McArthur (John R. McArthur)	Director	March 2, 2009
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	March 2, 2009
/s/ James Scarola (James Scarola)	Director	March 2, 2009
/s/ Paula J. Sims (Paula J. Sims)	Director	March 2, 2009
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	March 2, 2009

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.

Date: March 2, 2009

FLORIDA POWER CORPORATION
(Registrant)

By: /s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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	March 2, 2009
/s/ Michael A. Lewis (Michael A. Lewis)	Director	March 2, 2009
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	March 2, 2009
/s/ John R. McArthur (John R. McArthur)	Director	March 2, 2009
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	March 2, 2009
/s/ Paula J. Sims (Paula J. Sims)	Director	March 2, 2009
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	March 2, 2009

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 (filed as Exhibit 3b(2) to the Annual Report on Form 10-K for the year ended December 31, 2007, as filed with the SEC on February 28, 2008, File No. 1-15929, 1-3382 and 1-3274).		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 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).	X
*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 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); the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated September 12, 2003, File No 1-3382); the Seventy-third Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 22, 2005, File No. 1-3382); the Seventy-fourth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated November 30, 2005, File No. 1-3382); the Seventy-fifth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 13, 2008, File No 1-3382); and the Seventy-sixth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated January 8, 2009, File No. 1-3382).	X

*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 Forty-sixth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on September 19, 2007); the Forty-seventh Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on December 13, 2007); and the Forty-eighth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on June 18, 2008).	X

*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 Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10(b), File No. 33-25560).	X
*10a(3)	Power Coordination Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982 (filed as Exhibit 10(c), File No. 33-25560).	X
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).	X
*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).	XXX
+*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)	XXX
+*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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	XXX
+*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).	XXX
+*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).	XXX
+*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).	XXX
+*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).	XXX
+*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).	XXX
+*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).	XXX

+*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)	XXX
+*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).	XXX
+*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).	XXX
+*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).	XXX
+*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)	XXX
+*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).	XXX
+*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).	XXX
+*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 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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274)		X	
+*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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).			
+*10c(23)	Form of Executive and Key Manager 2008 Performance Share Sub-Plan (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended March 31, 2008, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+10c(24)	Form of Restricted Stock Unit Award Agreement (filed as Exhibit 10(b) to Quarterly Report on Form 10-Q for the period ended March 31, 2008, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
*10d(1)	Agreement dated November 18, 2004 between Winchester Production Company, Ltd., TGG Pipeline Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 10d(1) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X		X
*10d(2)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company ("SNG"), Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between SNG and PEF, dated December 2, 2004; b) Gas Sale and Purchase Contract between BG and PEF, dated December 1, 2004; c) Interim Firm Transportation Service Agreement by and between FGT and PEF, dated December 2, 2004; d) Letter Agreement between FGT and PEF, dated December 2, 2004 and Firm Transportation Service Agreement by and between FGT and PEF to be entered into upon satisfaction of certain conditions precedent; e) Discount Agreement between FGT and PEF, dated December 2, 2004; f) Amendment to Gas Sale and Purchase Contract between BG and PEF, dated January 28, 2005; and 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

*10d(3)	Engineering, Procurement and Construction Agreement, dated as of December 31, 2008, between Florida Power Corporation d/b/a/ Progress Energy Florida, Inc., as owner, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for a two-unit AP1000 Nuclear Power Plant (filed as Exhibit 10.1 to Current Report on Form 8-K filed on March 2, 2009). (The Registrants' have requested confidential treatment for certain portions of this exhibit pursuant to an application for confidential treatment submitted to the SEC. 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 No. 12(a)

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31

(dollars in millions)		2008		2007		2006		2005		2004
EARNINGS, AS DEFINED:										
Income from continuing operations before minority interest	$	**778**	$	702	$	567	$	527	$	552
Fixed charges, as below		**698**		625		652		607		588
Preferred dividend requirements		**(7)**		(7)		(7)		(6)		(7)
Minority interest		**(5)**		(9)		(16)		(4)		–
Income taxes, as below		**390**		329		334		293		333
Total earnings, as defined	$	**1,854**	$	1,640	$	1,530	$	1,417	$	1,466
FIXED CHARGES, AS DEFINED:										
Interest on long-term debt	$	**618**	$	553	$	619	$	565	$	526
Other interest		**61**		52		12		23		43
Imputed interest factor in rentals – charged principally to operating expenses		**12**		13		14		13		12
Preferred dividend requirements of subsidiaries		**7**		7		7		6		7
Total fixed charges, as defined	$	**698**	$	625	$	652	$	607	$	588
INCOME TAXES:										
Income tax expense (benefit)	$	**395**	$	334	$	339	$	298	$	338
Included in AFUDC – deferred taxes in book depreciation		**(5)**		(5)		(5)		(5)		(5)
Total income taxes	$	**390**	$	329	$	334	$	293	$	333
Ratio of Earnings to Fixed Charges		**2.66**		2.62		2.35		2.33		2.49

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)	2008	2007	2006	2005	2004
EARNINGS, AS DEFINED:					
Income before cumulative effect of changes in accounting principles	$ **534**	$ 501	$ 457	$ 493	$ 461
Fixed charges, as below	**227**	223	225	205	201
Income taxes, as below	**293**	290	260	234	234
Total earnings, as defined	$ **1,054**	$ 1,014	$ 942	$ 932	$ 896
FIXED CHARGES, AS DEFINED:					
Interest on long-term debt	$ **210**	$ 214	$ 218	$ 191	$ 183
Other interest	**9**	1	(1)	6	11
Imputed interest factor in rentals – charged principally to operating expenses	**8**	8	8	8	7
Total fixed charges, as defined	**227**	223	225	205	201
Preferred dividends, as defined	**5**	5	5	4	5
Total fixed charges and preferred dividends combined	$ **232**	$ 228	$ 230	$ 209	$ 206
INCOME TAXES:					
Income tax expense	$ **298**	$ 295	$ 265	$ 239	$ 239
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(5)	(5)
Total income taxes	$ **293**	$ 290	$ 260	$ 234	$ 234
Ratio of Earnings to Fixed Charges	**4.64**	4.55	4.19	4.55	4.45
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.54**	4.45	4.10	4.46	4.36

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)	**2008**	2007	2006	2005	2004
EARNINGS, AS DEFINED:					
Net income	$ **385**	$ 317	$ 328	$ 260	$ 335
Fixed charges, as below	**239**	188	159	138	122
Income taxes	**181**	144	193	121	174
Total earnings, as defined	$ **805**	$ 649	$ 680	$ 519	$ 631
FIXED CHARGES, AS DEFINED:					
Interest on long-term debt	$ **220**	$ 157	$ 145	$ 116	$ 107
Other interest	**16**	28	10	18	10
Imputed interest factor in rentals – charged principally to operating expenses	**3**	3	4	4	5
Total fixed charges, as defined	**239**	188	159	138	122
Preferred dividends, as defined	**2**	2	2	2	2
Total fixed charges and preferred dividends combined	$ **241**	$ 190	$ 161	$ 140	$ 124
Ratio of Earnings to Fixed Charges	**3.37**	3.45	4.28	3.76	5.17
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**3.34**	3.42	4.22	3.71	5.08

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, 2008 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. 333-70332 on Form S-8, Registration Statement No. 333-78157 on Form S-4, Registration Statement No. 333-104951 on Form S-8, Registration Statement No. 333-104952 on Form S-8, Registration Statement No. 333-155418 on Form S-3, Registration Statement No. 333-155418-03 on Form S-3, Registration Statement No. 333-155418-04 on Form S-3, Registration Statement No. 333-155418-05 on Form S-3, Registration Statement No. 333-155541 on Form S-8 and Registration Statement No. 333-155543 on Form S-8 of our report dated March 2, 2009, relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2008, 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, 2008

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

Exhibit No. 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333−155418-02 on Form S−3 of our report dated March 2, 2009, 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 expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2008, 2007 and 2006), appearing in this Annual Report on Form 10-K of PEC for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

Exhibit No. 23(c)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-155418-01 on Form S-3 of our report dated March 2, 2009, relating to the financial statements and financial statement schedule of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2008, 2007 and 2006), appearing in this Annual Report on Form 10-K of PEF for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

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 in order 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: March 2, 2009

By: /s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION

I, Mark F. Mulhern, 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 in order 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: March 2, 2009

By: /s/ Mark F. Mulhern
Mark F Mulhern
Senior 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 in order 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 (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: March 2, 2009

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

Exhibit 31(d)

CERTIFICATION

I, Mark F. Mulhern, 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 in order 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 (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: March 2, 2009

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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 in order 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 is made known to us by others within that entity, 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 (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: March 2, 2009

By: /s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer

Exhibit 31(f)

CERTIFICATION

I, Mark F. Mulhern, 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 in order 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 is made known to us by others within that entity, 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 (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: March 2, 2009

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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 period ended December 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
March 2, 2009

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 period ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark F. Mulhern, Senior 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/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and
Chief Financial Officer
March 2, 2009

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 period ended December 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
March 2, 2009

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 period ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark F. Mulhern, Senior 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/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and
Chief Financial Officer
March 2, 2009

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 period ended December 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
March 2, 2009

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 period ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark F. Mulhern, Senior 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/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and
Chief Financial Officer
March 2, 2009

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.

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, 2009

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	(X)	No	( )

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 registrant was 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 whether each registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

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

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

Progress Energy	(X)
PEC	(X)
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, 2009, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $10,535,128,179. As of June 30, 2009, 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, 2009, 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, 2010, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	284,621,114
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 2010 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, acronyms or initialisms 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
ARB	Accounting Research Bulletin
ARO	Asset retirement obligation
ASLB	Atomic Safety and Licensing Board
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Base Revenues	Non-GAAP measure defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues
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
CCRC	Capacity Cost-Recovery Clause
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, which were sold on March 7, 2008
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Corporate and Other	Corporate and Other segment primarily includes the Parent, Progress Energy Service Company and miscellaneous other nonregulated businesses
CR1 and CR2	PEF's Crystal River Units No. 1 and 2 coal-fired steam turbines
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 Customer Association
CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DSM	Demand-side management
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three were wholly owned
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

EIP	Equity Incentive Plan
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement and construction
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
Fitch	Fitch Ratings
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
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
the Georgia Contracts	Full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO
Georgia Operations	Former reporting unit consisting of the Effingham, Monroe, Walton and Washington nonregulated generation plants in service and the Georgia Contracts
GHG	Greenhouse gas
Global	U.S. Global, LLC
GridSouth	GridSouth Transco, LLC
GWh	Gigawatt-hours
Harris	PEC's Shearon Harris Nuclear Plant
IPP	Progress Energy Investor Plus Plan
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Levy	PEF's proposed nuclear plant in Levy County, Fla.
LIBOR	London Inter Bank Offered Rate
MACT	Maximum achievable control technology
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
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCUC	North Carolina Utilities Commission
NDT	Nuclear decommissioning trust
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 NOx State Implementation Plan Call rule which requires 22 states including North Carolina, South Carolina and Georgia (but excluding Florida) to further reduce emissions of nitrogen oxides
NRC	United States Nuclear Regulatory Commission
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income

Ongoing Earnings	Non-GAAP financial measure that includes results from continuing operations after excluding the effects of certain identified gains and charges
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
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
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PUHCA 2005	Public Utility Holding Company Act of 2005
PVI	Progress Energy Ventures, Inc., formerly referred to as Progress Ventures, Inc.
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REPS	Renewable energy portfolio standard
Robinson	PEC's Robinson Nuclear Plant
RSU	Restricted stock unit
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
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
(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
S&P	Standard & Poor's Rating Services
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, which were sold on March 7, 2008
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
VIE	Variable interest entity
Ward	Ward Transformer site located in Raleigh, N.C.
Ward OU1	Operable unit for stream segments downstream from the Ward site
Ward OU2	Operable unit for further investigation at the Ward facility and certain adjacent areas

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, future liquidity requirements and estimated capital expenditures through the year 2012; and d) "Other Matters" about the effects of new environmental regulations, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction and our synthetic fuels tax credits.

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 energy policy; our ability to recover eligible costs and earn an adequate return on investment through the regulatory process; the ability to successfully operate electric generating facilities and deliver electricity to customers; the impact on our facilities and businesses from a terrorist attack; the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and regulations; risks associated with climate change; 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; 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 expense (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to Progress Energy, Inc. holding company (the Parent); current economic conditions; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; the impact that increases in leverage or reductions in cash flow may have on each of the Progress Registrants; the Progress Registrants' ability to maintain their current credit ratings and the impacts in the event their credit ratings are downgraded; the investment performance of our nuclear decommissioning trust (NDT) funds; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; the impact of potential goodwill impairments; 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); and the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements. 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 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 management assess the effect of each such factor on the Progress Registrants.

PART I

ITEM 1. BUSINESS

GENERAL

ORGANIZATION

Progress Energy, Inc. is a public utility holding company primarily engaged in the regulated electric utility business. Headquartered in Raleigh, N.C., it owns, directly or indirectly, all of the outstanding common stock of its utility subsidiaries and varying percentages of other nonregulated subsidiaries. As discussed in Note 3, most nonregulated business operations have been divested in recent years. In this report, Progress Energy, which includes 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. We acquired PEF through our November 2000 acquisition of its parent, Florida Progress Corporation (Florida Progress).

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). Included within its broad authority, the FERC's approval is required prior to any merger involving a public utility and prior to the disposition of any utility asset with a market value in excess of $10 million. The FERC prohibits market participants from intentionally or recklessly making any fraudulent or misleading statements with regard to transactions subject to the FERC's jurisdiction.

Our reportable 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 in portions of Florida, respectively. 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 (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 19 for information regarding the revenues, income and assets attributable to our business segments.

The Utilities have more than 22,000 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 have historically had population growth higher than the U.S. average. However, like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. 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.

For the year ended December 31, 2009, our consolidated revenues were $9.885 billion and our consolidated assets at year-end were $31.236 billion

RECENT DEVELOPMENTS

In 2009, we concentrated on strategies to address current economic conditions and the ongoing public policy debate on energy and the environment. We continued our efforts toward implementing our balanced solution strategy of energy efficiency, alternative energy and state-of-the-art power generation. The utility industry as a whole faces significant cost pressures and lower retail energy sales. We focused on continuous business excellence, cost management and operational efficiency to help offset lower energy sales at the Utilities.

In 2009, PEF successfully sought and received interim and limited rate relief and nuclear cost recovery in Florida. However, in January 2010, in response to a base rate case PEF filed with the Florida Public Service Commission (FPSC) in 2009, the FPSC voted to grant PEF no increase in base rates above the approximately $132 million annual revenue requirement that had been previously awarded in 2009 as limited rate relief for the repowered Bartow Plant. We believe the PEF revenue level approved is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. Consequently, we are currently reviewing our regulatory options in Florida. As a result of the FPSC's decision, Fitch Ratings, Moody's Investors Services, Inc. and Standard and Poor's Rating Services have indicated that they believe the risk related to Florida's regulatory environment has increased. This perceived increased risk, along with the revenue requirements level approved in the FPSC decision, has caused the rating agencies to put certain credit ratings of PEF, and in some cases the Parent and PEC, on negative watch. See MD&A – "Liquidity and Capital Resources – Credit Rating Matters" for additional information regarding our credit ratings.

While we have not made a final determination on nuclear construction, in 2009 we continued to take steps to keep open the option of building a plant or plants at Shearon Harris Nuclear Plant (Harris) in North Carolina and at a greenfield site in Levy County, Florida (Levy). We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce greenhouse gas (GHG) emissions, as well as existing state legislative policy, which is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a combined license (COL) by the United States Nuclear Regulatory Commission (NRC) remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance. This resulted in a minimum 20-month in-service schedule shift for the Levy units. As discussed in "Nuclear Matters – Potential New Construction," additional schedule shifts are likely. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

During 2009, there were a number of state and federal initiatives related to energy and environmental policy. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future. We are expanding and enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. We continue to actively pursue alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. We announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions. We also placed into service pollution control equipment (or scrubbers) on PEC's Mayo Plant and PEF's Crystal River Unit No. 5 (CR5). Additionally, we were notified of our selection for grant negotiations under The American Recovery and Reinvestment Act's Smart Grid technology development grant program. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the grant program.

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; Nuclear Project 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 2025 of $4.5 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. PEF continues to seek ways to address the impact of escalating payments under these contracts. However, the 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.

WHOLESALE COMPETITION

The Utilities compete with other utilities and merchant generators 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 attract new wholesale customers and to retain current wholesale customers who have existing contracts with PEC or PEF.

In June 2009, PEC executed a contract extension with its largest municipal wholesale customer, Public Works Commission of the City of Fayetteville, N.C. The 20-year agreement extends the current contract, representing more than 500 MW of electricity load, through 2032.

Enacted in 2005, the Energy Policy Act of 2005 (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 transmission providers with an OATT on file with the FERC, PEC and PEF are required to comply with the requirements of the rule. A major requirement of the rule was to file a revised pro forma OATT on July 13, 2007. PEC and PEF made the required FERC filing, and both 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. PEC and PEF made compliance filings on March 17, 2008, in order to meet the requirements of Order 890-A. The FERC approved PEC's and PEF's Order 890-A filings on March 30, 2009.

Effective for PEC on July 1, 2008, and for PEF on January 1, 2008, the Utilities moved from either fixed-revenue requirement or fixed-rate OATT rates to formula-based OATT rates. Under the formula-based rates, the transmission rates are updated each year based on actual costs. The switch to formula-based rates increased PEC's 2008 revenues by $7 million and increased PEF's 2008 revenues by $2 million. The rate structure will have a greater impact on PEF in 2011 when all of PEF's wholesale customers become subject to the new structure. The Utilities filed updated OATT rates in 2009 that increased PEC's 2009 revenues by $4 million and PEF's by $2 million.

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 Order No. 890 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 is anticipated to include 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. FERC has approved both PEC's and PEF's regional grid planning processes subject to modification. PEF and PEC filed compliance filings with FERC on October 7, 2008, and December 17, 2008, respectively. PEC received approval from the FERC in January 2010, and PEF is still awaiting FERC approval.

The FERC requires that entities desiring to make wholesale sales of electricity at market-based rates document that they do not possess market power. Market power is exercised when an entity profitably drives up prices through its control of a single activity, such as electricity generation, where it controls a significant share of the total capacity available to the market. The FERC has established screening measures for such determinations. Given the difficulty PEC believed it would experience in passing one of the screens, PEC revised its market-based rate tariffs in 2005 to restrict PEC to sales outside of its control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. Accordingly, PEC and PEF make wholesale sales of electricity at cost-based rates in areas inside of PEC's control area and peninsular Florida and 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 this market-based rates decision.

REGIONAL TRANSMISSION ORGANIZATIONS

The FERC's Order 2000 established national standards for regional transmission organizations (RTOs) and advocated the view that regulated, unbundled transmission would facilitate competition in both wholesale and retail electricity markets. The Utilities previously participated in RTO efforts, but are not currently active in these efforts due to the FERC's termination of both the GridSouth Transco, LLC (GridSouth) and the GridFlorida RTO proceedings. GridSouth was terminated by the GridSouth participants due to not reaching a consensus on creating a southeastern RTO. GridFlorida was terminated by the FPSC and the FERC due to the conclusion that it was not beneficial to jurisdictional customers. PEC's recorded investment in GridSouth totaled $15 million at December 31, 2009. Excluding the immaterial South Carolina retail portion, the GridSouth costs will be fully amortized and recovered by 2012. 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 240 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, 15 expire during the period 2010 through 2014, and the remaining agreements expire between 2015 and 2069. PEC also provides service within a number of municipalities and in all of the unincorporated areas within its service area without franchise agreements.

PEF has nonexclusive franchises with varying expiration dates in 110 of the Florida municipalities in which it distributes electricity. PEF also provides service to 11 other municipalities and in all of the unincorporated areas within its service area without franchise agreements. The general effect of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. The franchise agreements cover periods ranging from 10 to 30 years with the majority covering 30-year periods from the date enacted. Of the 110 franchise agreements, 40 expire between 2010 and 2014, and the remaining agreements expire between 2015 and 2037.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

The Parent is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to 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

The Utilities are subject to regulation by a number of federal regulatory agencies, including the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), the NRC and the United States Environmental Protection Agency (EPA).

Reliability Standards

The FERC has certified the NERC as the electric reliability organization that will propose and enforce mandatory reliability standards for the bulk power electric system. Included in this certification was a provision for the delegation of authority to audit, investigate and enforce reliability standards in particular regions of the country by entering into delegation agreements with regional entities. In addition, the regional entities have the ability to formulate additional reliability standards in their respective regions, which are required to supplement and be more stringent than the NERC reliability standards. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

PEC and PEF are currently subject to certain reliability standards as registered users, owners and operators of the bulk power system. We expect existing reliability standards to migrate to more definitive and enforceable requirements over time and additional NERC and regional reliability standards to be approved by the FERC in coming years requiring us to take additional steps to remain compliant. 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 liquidity.

During 2008, PEC self-reported to the SERC three noncompliances with voluntary standards. PEC submitted and completed mitigation plans for these noncompliances with voluntary standards. PEC does not expect enforcement actions on noncompliances to voluntary standards. During 2008, PEC also self-reported to the SERC a violation of a mandatory standard and filed and completed a mitigation plan. PEC and the SERC have reached a settlement agreement on this violation and expect the settlement agreement to be submitted to the FERC for approval during 2010.

During 2009, PEC self-reported to the SERC three violations of mandatory standards. PEC has submitted mitigation plans to the SERC and is currently implementing these mitigation plans. PEC expects to enter into settlement discussions with the SERC for 2009 violations during the first quarter of 2010.

~~In 2010, PEC self-reported to the SERC four violations of mandatory standards. PEC is developing mitigation plans~~ for submittal to the SERC during the first quarter of 2010.

None of the noncompliances or violations 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.

During 2008, PEF self-reported to the FRCC four violations of mandatory standards. PEF has filed mitigation plans for the four mandatory violations and completed three of the mitigation plans. The fourth mitigation plan is on schedule and is expected to be completed during 2010. PEF and the FRCC have entered into settlement discussions related to these four violations and expect a settlement to be filed with the FERC during 2010.

During 2009, PEF self-reported to the FRCC eight violations of mandatory standards. PEF has submitted mitigation plans to the FRCC and is currently implementing these mitigation plans. PEF expects to enter into settlement discussions with the FRCC for 2009 violations during the first quarter of 2010.

In 2010, PEF self-reported to the FRCC eight violations of mandatory standards. PEF is developing mitigation plans for submittal to the FRCC during the first quarter of 2010.

None of the violations 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.

Nuclear

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. See "Nuclear Matters."

Environmental

The Utilities are also subject to regulation by the EPA. See "Environmental."

STATE REGULATION

PEC is subject to regulation in North Carolina by the North Carolina Utilities Commission (NCUC), and in South Carolina by the Public Service Commission of South Carolina (SCPSC). 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 net 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, with provisions that if PEC had experienced extraordinary events beyond its control, PEC could have petitioned for a rate increase. Since 2007, PEC's current North Carolina base rates have continued 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 remained 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, which PEF declined to extend. PEF's base rate agreement also provided for revenue sharing between PEF and its ratepayers with annual adjustment of the threshold and cap amounts. However, PEF's retail base revenues did not exceed the threshold in 2009 and thus no revenues were subject to the revenue-sharing provisions. The threshold and cap were $1.688 billion and $1.742 billion, respectively, for 2009.

In anticipation of the expiration of its current base rate settlement agreement, PEF filed a proposal with the FPSC in 2009 for an increase in base rates effective with the first billing cycle of January 2010. The $499 million request for increased base rates was based, in part, on PEF's investments in its generating fleet and its transmission and distribution systems (See Note 7C). In January 2010, the FPSC voted to grant PEF no increase in base rates above the approximately $132 million annual revenue requirements that had been previously awarded in 2009 as limited rate relief for the repowered Bartow Plant. See Note 7C for details regarding the difference between the $499 million increase in base rates requested and the $132 million increase granted. Among other items, the FPSC authorized a return on equity of 10.5 percent. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. Consequently, we are currently reviewing our regulatory options in Florida.

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, including any past over- or under-recovered costs, are prudent. The clauses are in addition to the Utilities' approved base rates. The Utilities generally 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 investments for energy efficiency and conservation, capacity costs, environmental compliance and utility plant. 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 DSM and energy-efficiency programs, costs of commodities such as ammonia and limestone used in emissions control technologies (reagents) and eligible renewable energy costs;
- *South Carolina Retail* – fuel costs, certain purchased power costs, costs of reagents, sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission allowance expenses, costs of new DSM and energy-efficiency programs; and

- *Florida Retail* – fuel costs, purchased power costs, capacity costs, qualified nuclear costs, energy conservation expense and specified environmental costs, including Clean Air Interstate Rule (CAIR), SO_2 and NOx emission allowance expenses.

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 associated regulatory treatment 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 imprudent. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the timing of cash flow of the Utilities.

As discussed more fully in MD&A – "Other Matters – Regulatory Environment," eligible nuclear costs not previously recoverable through cost-recovery clauses became recoverable in the Florida retail jurisdiction beginning in 2009.

Renewable Energy and Energy-Efficiency Standards

PEC is subject to renewable energy standards at the state level in North Carolina. North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) establishes minimum standards 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 NC 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 NC REPS law, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the NC REPS requirements if the NCUC determines it is in the public interest to do so.

Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard for Florida utilities. On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter. Until the rulemaking processes are completed, we cannot predict the costs of complying with the law but PEF would be able to recover its reasonable prudent compliance costs.

On December 30, 2009, the FPSC ordered PEF to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. Under the order, PEF's aggregate conservation goals over the next ten years are: 1,183 Summer MW, 1,072 Winter MW, and 3,488 gigawatt-hours (GWh). PEF has filed a motion for reconsideration with the FPSC to correct what we believe are oversights or errors. If accepted by the FPSC, PEF's motion would adjust conservation goals over the next ten years to: 808 Summer MW, 933 Winter MW, and 1,792 GWh. The FPSC is expected to make a decision in March 2010. We cannot predict the outcome of this matter.

Storm Recovery

As a result of the FPSC's January 11, 2010 base rate approval, PEF may not collect in base rates additional funds for its storm damage reserve. In the event future storms cause the reserve to be depleted, PEF can petition the FPSC for implementation of an interim surcharge to cover any deficiency of its storm reserve. Under Florida law, PEF also may securitize storm costs upon approval by the FPSC. At December 31, 2009, PEF's storm reserve totaled $136 million.

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, capital outlays for modifications and new plant construction, the technological and financial aspects of decommissioning plants at the end of their licensed lives and requirements relating to nuclear insurance. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

PEC owns and operates four nuclear generating units: Brunswick Nuclear Plant (Brunswick) Unit No. 1 and Unit No. 2, Harris, and Robinson Nuclear Plant (Robinson). The NRC has renewed the operating licenses for all of PEC's nuclear plants. The renewed operating licenses for Brunswick No. 1 and No. 2, Harris and Robinson expire in September 2036, December 2034, October 2046 and July 2030, respectively.

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. On December 18, 2008, PEF submitted an application to the NRC requesting a 20-year renewal of the CR3 operating license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

Over time, PEC and PEF have made various modifications of their nuclear facilities to increase the energy output. During CR3's fueling and maintenance outage that began in September 2009, PEF commenced a project to replace CR3's steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, the finalized repair estimates and replacement power costs, nor the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

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

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida (See Item 1A, "Risk Factors"). The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on the potential nuclear plant construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

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 17, 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. No petitions to intervene have been admitted in the Harris COL application. We cannot predict the outcome of this matter. 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 2019.

On December 12, 2006, we announced that PEF selected Levy 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. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. On October 6, 2008, the NRC docketed, or accepted for review, the Levy nuclear project 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. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the required 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On July 8, 2009, the Atomic Safety and Licensing Board (ASLB) issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and it is expected at this time that a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. On December 31, 2008, PEF signed an agreement with Westinghouse Electric Company LLC and Stone & Webster, Inc for the engineering, procurement and construction of two nuclear units at Levy. The contract price for the two Levy units combined is approximately $7.650 billion, part of which is subject to agreed upon escalation factors. The total escalated cost for the two generating units was estimated to be approximately $14 billion in PEF's petition for the Determination of Need for Levy, including land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. The necessary transmission equipment and approximately 200 miles of transmission lines associated with the project was estimated to cost an additional $3 billion.

In 2009, the NRC indicated it would not process PEF's limited work authorization request until after COL issuance. This factor alone resulted in a minimum 20-month in-service schedule shift for the Levy units. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule.

SECURITY

The NRC has issued various orders since September 2001 with regard to security at nuclear plants. These orders include additional restrictions on nuclear plant 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 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 Policy Act of 1982 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 and/or expansion 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 renewals, for their nuclear generating units. Harris has sufficient storage capacity through the expiration of its renewed operating licenses.

See MD&A – "Other Matters – Nuclear – Spent Nuclear Fuel Matters" and Note 22D, respectively, for discussion of the status of permanent disposal facilities and the Utilities' contracts with the DOE for spent nuclear fuel storage.

DECOMMISSIONING

In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the respective state utility commissions 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 4D for a discussion of the Utilities' nuclear decommissioning costs.

ENVIRONMENTAL

GENERAL

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."

We have a formal environmental management system to manage the environmental aspects and impacts to our businesses, which generally follows the international ISO 14001 standard. We have established a process to identify environmental risks, take prompt action to address these issues and ensure appropriate senior management oversight on a routine basis. Our business units assume daily responsibility for ensuring environmental compliance and are supported by several corporate organizations, including technical environmental professionals, governance and risk management staff and an energy policy and strategy group. The actions of these organizations are guided by our Environmental, Health and Safety Performance Council, which is composed of senior executives. The Environmental, Health and Safety Performance Council provides overall strategic direction, guides corporate environmental policy, monitors environmental regulatory compliance and approves targets that measure, track and drive performance. Our environmental activities are reported to our board of directors' Operations and Nuclear Oversight Committee. The committee is responsible for climate change oversight and strategy and therefore assesses our plans and activities and makes recommendations to the full board regarding these matters.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. 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 hazardous waste sites, including the Ward Transformer site (Ward) and several 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 submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. 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.

GLOBAL CLIMATE CHANGE

Global climate change is one of the primary corporate environmental risks identified by our environmental management system. Our risks associated with climate change are discussed under Item 1A, "Risk Factors."

Growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other GHGs. The full impact of final legislation, if enacted and additional regulation resulting from other GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant rate increases over time to recover the costs of compliance.

As previously discussed under "Recent Developments," we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. We are taking steps to address global climate change by changing the way we make electricity through our balanced solution strategy of energy efficiency, alternative energy and state-of-the-art power generation as discussed in MD&A – "Other Matters – Energy Demand." We continuously evaluate new generation options to determine if they are realistic for the Southeastern United States where our operations are located.

See Note 21 and MD&A – "Other Matters – Environmental Matters" for additional discussion of our environmental matters, including specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

~~At February 19, 2010, 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. Progress Energy and the International Brotherhood of Electrical Workers entered into a new three-year labor contract that began December 2008. 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.

At February 19, 2010, PEC and PEF employed approximately 5,500 and 4,000 full-time employees, respectively.

PEC

GENERAL

PEC is a regulated public utility founded in North Carolina in 1908 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2009, PEC had a total summer generating capacity (including jointly owned capacity) of 12,585 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's 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, 2009, PEC was providing electric services, retail and wholesale, to approximately 1.5 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. 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 net income available to parent was $513 million, $531 million and $498 million for the years ended December 31, 2009, 2008 and 2007, respectively. PEC's total assets were $13.502 billion and $13.165 billion at December 31, 2009 and 2008, 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:

	2009	2008	2007
Residential	**39%**	38%	37%
Commercial	**27%**	26%	26%
Wholesale	**16%**	17%	18%
Industrial	**16%**	17%	17%
Other retail	**2%**	2%	2%

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

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:

	2009	2008	2007
Coal	**44%**	45%	48%
Nuclear	**44%**	43%	42%
Oil/Gas	**6%**	4%	4%
Purchased power	**5%**	7%	5%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and certain purchased power costs to its customers through fuel cost-recovery 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:

(per million Btu)	**2009**	2008	2007
Coal	**$3.82**	$3.39	$2.96
Nuclear	**0.53**	0.46	0.44
Oil	**14.84**	16.05	12.28
Gas	**8.16**	10.66	9.19
Weighted-average	**2.60**	2.44	2.21

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.

<u>Coal</u>

PEC anticipates a burn requirement of approximately 13.5 million tons of coal in 2010. Almost all of the coal will be supplied from Appalachian coal sources and will be primarily delivered by rail.

For 2010, PEC has short-term, intermediate and long-term agreements from various sources for approximately 100 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.

As discussed within MD&A – "Results of Operation – Progress Energy Carolina – Operation and Maintenance," PEC has announced that it intends to permanently shut-down certain coal-fired units representing approximately 30 percent of its coal-fired power generation fleet between 2013 and the end of 2017 as part of a major coal-to-gas modernization strategy. See "Oil and Gas" for planned gas facilities.

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 fifteen 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 various suppliers and PEC has derivative instruments to limit its exposure to price fluctuations. PEC has dual-fuel generating facilities 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 gas generation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity under other contracts and utilizes transportation for its peaking load requirements.

The NCUC has granted PEC permission to construct two new generating facilities: a 600-MW combined cycle dual-fuel facility at its Richmond County, N.C. generating facility and a 950-MW combined cycle natural gas-fueled facility at a site in Wayne County, N.C. The facilities are expected to be placed in service in 2011 and 2013, respectively. PEC has also filed for approval to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C., projected to be placed in service by late 2013 or early 2014.

Purchased Power

PEC purchased approximately 3.3 million MWh, 4.8 million MWh and 3.9 million MWh of its system energy requirements during 2009, 2008 and 2007, respectively, under purchase obligations and operating leases and had 1,309 MW of firm purchased capacity under contract during 2009. PEC may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEC believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

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 summer generating 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 2010. The Walters Plant license will expire in 2034.

PEF

GENERAL

PEF is a regulated public utility founded in Florida in 1899 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. At December 31, 2009, PEF had a total summer generating capacity (including jointly owned capacity) of 10,013 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 10,822 MWh was set on January 11, 2010.

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, 2009, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Municipal Power Agency, the city of Gainesville, Tampa Electric Company, and Reedy Creek Improvement District. 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 net income available to parent was $460 million, $383 million and $315 million for the years ended December 31, 2009, 2008 and 2007, respectively. PEF's total assets were $13.100 billion and $12.471 billion at December 31, 2009 and 2008, 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:

	2009	2008	2007
Residential	**53%**	50%	52%
Commercial	**26%**	25%	25%
Wholesale	**8%**	12%	9%
Industrial	**6%**	7%	7%
Other retail	7%	6%	7%

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:

	2009	2008	2007
Oil/Gas	**44%**	34%	32%
Coal	**25%**	30%	31%
Purchased Power	**20%**	21%	23%
Nuclear	**11%**	15%	14%

PEF is generally permitted to pass the cost of fuel and certain purchased power to its customers through fuel cost-recovery 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:

(per million Btu)	**2009**	2008	2007
Oil	**$11.43**	$9.24	$8.54
Gas	**8.40**	10.03	8.51
Coal	**4.25**	3.74	3.28
Nuclear	**0.52**	0.49	0.48
Weighted-average	**5.88**	5.67	4.85

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.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from various suppliers and PEF has derivative instruments to limit its exposure to price fluctuations. 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 also purchases capacity under other contracts and utilizes transportation for its peaking load requirements.

Coal

PEF anticipates a requirement of approximately 5.5 million tons of coal in 2010. Approximately 60 percent of the coal is expected to be supplied from Appalachian coal sources and 40 percent supplied from coal sources in the Illinois Basin and Colorado. Approximately 30 percent of the coal is expected to be delivered by rail and the remainder by water.

For 2010, PEF has intermediate and long-term contracts from various sources for approximately 100 percent of its estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to ten years.

Purchased Power

PEF purchased approximately 8.7 million MWh, 10.2 million MWh and 11.1 million MWh of its system energy requirements during 2009, 2008 and 2007, respectively, under purchase obligations, operating leases and capital leases and had 1,847 MW of firm purchased capacity under contract during 2009. These agreements include approximately 682 MW of firm capacity under contract with certain QFs. PEF may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEF believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

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 for the foreseeable future. PEF's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEF's plans with respect to spent fuel storage, see "Nuclear Matters."

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, which generates essentially all of the segment's revenues. 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 reportable business segment.

The Corporate and Other segment's net loss attributable to controlling interests was $216 million, $84 million and $309 million for the years ended December 31, 2009, 2008 and 2007, respectively. Corporate and Other segment total assets were $20.538 billion and $17.483 billion at December 31, 2009 and 2008, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**40,420**	46,771	51,163	48,770	52,306
Nuclear	**29,412**	30,565	30,336	30,602	30,120
Combustion Turbines/Combined Cycle	**21,254**	15,557	13,319	11,857	11,349
Hydro	**651**	429	415	594	749
Purchased	**11,996**	14,956	14,994	14,664	14,566
Total energy supply (Company share)	**103,733**	108,278	110,227	106,487	109,090
Jointly owned share[a]	**5,500**	5,780	5,351	5,224	5,388
Total system energy supply	**109,233**	114,058	115,578	111,711	114,478
Average fuel cost (per million Btu)					
Fossil	**$5.50**	$5.35	$4.54	$4.17	$4.05
Nuclear fuel	**$0.53**	$0.46	$0.45	$0.44	$0.44
All fuels	**$3.79**	$3.66	$3.17	$2.86	$2.83
Energy sales (millions of kWh)					
Retail					
Residential	**36,516**	36,328	37,112	36,280	36,558
Commercial	**25,523**	26,080	26,215	25,333	25,258
Industrial	**13,653**	15,174	15,721	16,553	16,856
Other Retail	**4,753**	4,768	4,805	4,695	4,608
Unbilled	**491**	(107)	(61)	(272)	(460)
Wholesale	**17,801**	21,063	21,333	19,018	21,157
Total energy sales	**98,737**	103,306	105,125	101,607	103,977
Company uses and losses	**4,996**	4,972	5,102	4,880	5,113
Total energy requirements	**103,733**	108,278	110,227	106,487	109,090
Operating revenues (in millions)					
Retail					
Billed	**$8,449**	$7,585	$7,672	$7,429	$6,607
Unbilled	**14**	7	1	(6)	(2)
Wholesale	**1,114**	1,288	1,191	1,039	1,103
Miscellaneous revenue	**301**	280	270	263	238
Total operating revenues of the Utilities	**$9,878**	$9,160	$9,134	$8,725	$7,946

[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				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**27,261**	28,363	30,770	28,985	29,780
Nuclear	**24,467**	24,140	24,212	24,220	24,291
Combustion Turbines/Combined Cycle	**3,634**	2,795	2,960	2,106	2,475
Hydro	**651**	429	415	594	749
Purchased	**3,251**	4,735	3,901	4,229	4,656
Total energy supply (Company share)	**59,264**	60,462	62,258	60,134	61,951
Jointly owned share[(a)]	**5,057**	5,205	4,800	4,649	4,857
Total system energy supply	**64,321**	65,667	67,058	64,783	66,808
Average fuel cost (per million Btu)					
Fossil	**$4.30**	$4.01	$3.50	$3.37	$3.30
Nuclear fuel	**$0.53**	$0.46	$0.44	$0.43	$0.42
All fuels	**$2.60**	$2.44	$2.21	$2.06	$2.03
Energy sales (millions of kWh)					
Retail					
Residential	**17,117**	17,000	17,200	16,259	16,664
Commercial	**13,639**	13,941	14,032	13,358	13,313
Industrial	**10,368**	11,388	11,901	12,393	12,716
Other Retail	**1,497**	1,466	1,438	1,419	1,410
Unbilled	**360**	(8)	(55)	(137)	(235)
Wholesale	**13,966**	14,329	15,309	14,584	15,673
Total energy sales	**56,947**	58,116	59,825	57,876	59,541
Company uses and losses	**2,317**	2,346	2,433	2,258	2,410
Total energy requirements	**59,264**	60,462	62,258	60,134	61,951
Operating revenues (in millions)					
Retail					
Billed	**$3,801**	$3,582	$3,534	$3,268	$3,133
Unbilled	**5**	8	–	(1)	4
Wholesale	**707**	737	754	720	759
Miscellaneous revenue	**114**	102	97	99	95
Total operating revenues	**$4,627**	$4,429	$4,385	$4,086	$3,991

[(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				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**13,159**	18,408	20,393	19,785	22,526
Nuclear	**4,945**	6,425	6,124	6,382	5,829
Combustion Turbines/Combined Cycle	**17,620**	12,762	10,359	9,751	8,874
Purchased	**8,745**	10,221	11,093	10,435	9,910
Total energy supply (Company share)	**44,469**	47,816	47,969	46,353	47,139
Jointly owned share[(a)]	**443**	575	551	575	531
Total system energy supply	**44,912**	48,391	48,520	46,928	47,670
Average fuel cost (per million Btu)					
Fossil	**$6.88**	$6.87	$5.80	$5.09	$4.88
Nuclear fuel	**$0.52**	$0.49	$0.48	$0.50	$0.51
All fuels	**$5.88**	$5.67	$4.85	$4.21	$4.15
Energy sales (millions of kWh)					
Retail					
Residential	**19,399**	19,328	19,912	20,021	19,894
Commercial	**11,884**	12,139	12,183	11,975	11,945
Industrial	**3,285**	3,786	3,820	4,160	4,140
Other Retail	**3,256**	3,302	3,367	3,276	3,198
Unbilled	**131**	(99)	(6)	(135)	(225)
Wholesale	**3,835**	6,734	6,024	4,434	5,484
Total energy sales	**41,790**	45,190	45,300	43,731	44,436
Company uses and losses	**2,679**	2,626	2,669	2,622	2,703
Total energy requirements	**44,469**	47,816	47,969	46,353	47,139
Operating revenues (in millions)					
Retail					
Billed	**$4,648**	$4,003	$4,138	$4,161	$3,474
Unbilled	**9**	(1)	1	(5)	(6)
Wholesale	**407**	551	437	319	344
Miscellaneous revenue	**187**	178	173	164	143
Total operating revenues	**$5,251**	$4,731	$4,749	$4,639	$3,955

(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, is updated periodically in the reports the Progress Registrants file with the SEC. 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 required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of our business, including customer rates, retail service territories, reliability of our transmission system, applicable renewable energy and energy-efficiency standards, environmental compliance, issuances of securities, asset acquisitions and sales, accounting policies and practices, and the operation of generating facilities. 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. Changes in laws and regulations as well as changes in federal administrative policy are ongoing and the ultimate costs of compliance cannot be precisely estimated. Such changes could have an adverse impact on our financial condition and results of operations.

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 and ability to earn an adequate return on investment could be adversely affected if we do not control and prudently manage costs to the satisfaction of regulators, or if we do not obtain successful outcomes in our regulatory proceedings. Such regulatory decisions may be impacted by economic and public policy considerations within the respective jurisdictions.

The NCUC, the SCPSC and the FPSC each exercise regulatory authority for review and approval of the retail electric power rates charged within its respective state. The Utilities' state utility commissions approve base rates, which by law must give a utility a reasonable opportunity to recover its operating costs and return on invested capital. They also approve recovery of certain additional costs, known as "pass-through" costs, over and above base rates through cost-recovery clauses, which vary by jurisdiction; examples include fuel costs, certain purchased power costs, qualified nuclear costs and specified environmental costs. The commissions can disagree with our request of appropriate base rates, and can disallow either requested base rates or pass-through recoveries on the grounds that such costs were not reasonable and prudent.

The Utilities expect increased future expenditures in several key areas including, but not limited to, environmental compliance, new and existing generation, transmission and distribution facilities, renewable energy and energy-efficiency standards compliance (as applicable), DSM programs and fuel and other commodities. Such cost increases will be subject to scrutiny from regulators, policymakers and ratepayers. As referenced above, the commissions may disallow any costs that they find unreasonable and imprudent.

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

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

- operator error and breakdown or failure of equipment or processes, including repair and replacement power costs;
- failure of information technology systems and network infrastructure;
- operational limitations imposed by environmental or other regulatory requirements;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes and inability to recruit and retain skilled technical workers;
- inability to successfully and timely execute repair, maintenance and/or refueling outages;
- interruptions to the supply of fuel and other commodities used in generation;
- failure to comply with FERC-mandated reliability standards for the bulk power electric system;
- inadequate coal combustion product management (disposal or beneficial use) capabilities; and
- catastrophic events such as hurricanes, floods, extreme drought, earthquakes, fires, explosions, terrorist attacks, pandemic health events or other similar occurrences.

Occurrences of these events could adversely affect our financial condition or results of operations.

Meeting the anticipated demand in our service territories and fulfilling our environmental compliance strategies will require, among other things, modernization of coal generation facilities, the construction within the next decade of new generation facilities 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 demand within the Utilities' service territories and complying with existing and potential environmental laws and regulations 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.

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

<u>Energy-Efficiency and New Energy Resources</u>

We are expanding our DSM, energy-efficiency and conservation programs and will continue to pursue additional initiatives as these programs can be effective ways to reduce energy costs, offset the need for new power plants and protect the environment.

We are subject to the risk that our customers may not participate in our conservation programs or that the results from these programs may be less than anticipated. This could impact our compliance with state-mandated energy-efficiency standards as discussed in the risks regarding renewable energy standards. Also, not achieving the energy-efficiency and conservation measurements we assumed in our long-term resource planning could require us to further expand our generation or purchase additional power at prevailing market rates.

We are also subject to the risk that customer participation in these programs or new technologies that impact the quantity and pattern of electricity usage may decrease our electric sales and require us to seek future rate increases to cover our prudently incurred costs.

As discussed further in the risk factor related to renewable energy standards, we are actively engaged in a variety of alternative energy projects. 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. In 2009, we announced our intention to retire certain coal-fired units in North Carolina that do not have emission control equipment and to construct new natural gas-fueled units at certain of these facilities. We are also evaluating the possibility of converting certain of these facilities to be fueled by natural gas or biomass. At this time, no definitive decision has been made regarding the construction of nuclear plants.

Decisions to build new power plants and successful completion of such construction projects are based on many 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, including the ability to recover costs and earn an appropriate return on investment;
- operational performance of new technologies;
- the time required to permit and construct;
- environmental impact;
- both public and policymaker support, including support for siting of power plant and associated transmission;
- siting and construction of transmission facilities;
- cost and availability of construction equipment, materials and skilled labor;
- nuclear decommissioning costs, insurance, and costs of security;
- ability to obtain financing on favorable terms; and
- availability of adequate water supply.

There is no assurance that we will be able to successfully and timely construct new generation facilities or to expand or modernize existing facilities within our projected budgets or that those expenditures will be recoverable through our base rates or other recovery mechanisms. As with any major construction undertaking, completion could be delayed or prevented, or cost overruns could be incurred, as a result of numerous factors, including shortages of material and labor, labor disputes, weather interferences, difficulties in obtaining necessary licenses or permits or complying with license or permit conditions, and unforeseen engineering, environmental or geological problems. These construction projects are long-term and may involve facility designs that have not been previously constructed or that have not been finalized when that project is commenced. Consequently, the projects could be subject to significant cost increases for labor, materials, scope changes and changes in design. Unsuccessful construction, expansion or modernization efforts could be subject to additional costs and/or the write-off of our investment in the project or improvement.

The construction of new power plants 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. For certain new baseload generation facilities, we may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks, 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.

Our assumptions regarding future growth and resulting power demand in our service territories may not be realized. Like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. We may increase our baseload capacity based on anticipated growth levels and have excess capacity if those levels are not realized. The resulting 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.

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 and a viable program for managing spent nuclear fuel. We cannot provide certainty that these conditions will exist. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. We will continue to evaluate the ongoing viability of our nuclear construction projects based on certain criteria, including obtaining the COL, public, regulatory and political support; adequate financial cost-recovery mechanisms; and availability and terms of capital financing. Adverse changes in these criteria could result in project cost increases or project termination.

PEF has entered into an EPC agreement for Levy. More than half of the contract price is fixed or firm with agreed upon escalation factors. Generally, the EPC contractor will not be obligated to pay liquidated damages for events or circumstances that adversely affect its ability to fulfill its obligations to the extent that the events or circumstances are beyond its reasonable control and are not caused by its or its subcontractors' negligence or lack of due diligence and could not have been avoided by the use of its reasonable efforts. For termination without cause, the EPC agreement contains exit provisions with termination fees and costs, which may be significant, that vary based on the termination circumstance. Under the EPC agreement, we are responsible for a number of matters in connection with the construction, completion and start-up of Levy, including obtaining the COL; performance, oversight and review of certain surveillance and testing functions; and acceptance of turnover of systems from the EPC contractor. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and exit costs that would increase its unrecovered investment. The magnitude of these contract suspension, termination and/or exit costs cannot be determined at this time.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant constructed by us would qualify for these 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. Existing pipelines will have to be extended to the new plant locations prior to commencement of operations, which introduces the risks associated with a critical construction project not under our direct control. Power plants fueled by fossil fuels such as natural gas and fuel oil emit GHG, which may be subject to future regulation.

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, including, but not limited to, consideration of emissions that impact air and water quality and management of coal combustion products such as slag, bottom ash and fly ash.

We are subject to renewable energy standards that may have a negative impact on our business, financial condition and results of operations.

We are subject to state renewable energy standards in North Carolina. North Carolina's standards include use of energy from specified renewable energy resources or implementation of energy-efficiency measures totaling 12.5 percent by 2021. Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard but the rulemaking process is not complete. We may be subject to additional state or federal level standards in the future that 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 energy sources that are not cost-effective in order to comply with requirements. If we are not able to receive retail rates reflecting our costs or investments to comply with the state or federal standards. our financial condition and results of operation may be adversely affected.

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 financial exposures in excess of our insurance coverage.

PEC operates four nuclear units (three of which are jointly owned) and PEF jointly owns and operates one nuclear unit. In addition, we are exploring the possibility of expanding our nuclear generating capacity to meet future expected baseload generation needs. Our nuclear facilities are subject to operational, environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, maintaining adequate capital reserves for decommissioning, limitations on amounts and types of insurance available, potential operational liabilities and extended outages, 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. For PEF, it may incur liabilities to co-owners in the event of extended outages or operation at less than full capacity. If the Utilities are not allowed to recover the additional costs incurred either through insurance or regulatory mechanisms, our results of operations could be negatively impacted.

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 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.

With the prospect of 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.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and 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 and permits 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. 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.

Our coal-fired plants produce coal combustion products, primarily ash. The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products. PEC's impoundment dams are subject to additional state regulation due to a North Carolina law enacted in 2009. Until the applicable state agency inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or additional environmental controls for groundwater protection, and future mitigation of related impacts could have a material impact on our results of operations or financial condition.

Our compliance with environmental regulations, including those to reduce emissions of NOx, SO_2 and mercury from coal-fired power plants, requires significant capital expenditures that impact our financial condition. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. 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 needed to comply with requirements set by various environmental regulations increases our operating costs and reduces the generating capacity of our coal-fired plants. O&M expenses significantly increase due to the additional personnel, materials and general maintenance associated with operation of the equipment. Operation of the emission control equipment requires the procurement of significant quantities of reagents, such as limestone and ammonia. Future increases in demand for these items from other utility companies operating similar equipment could increase our costs associated with operating the equipment. Additionally, the operation of emission control equipment may result in the development of collateral issues that require further remedial actions, resulting in additional expenditures and operating costs.

We are subject to risks associated with climate change, which could have a negative impact on our business, financial condition and results of operations. Future legislation or regulation may impose significant restrictions on CO_2 and other GHG emissions. We may incur significant costs to comply with such legislation or regulation. Physical risks associated with climate change could impact us.

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. Any future legislative or regulatory actions taken to address global climate change represent a business risk to our operations and the full impact of such initiatives on our operations cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery. 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

According to the Intergovernmental Panel on Climate Change, potential climate change impacts in the southeastern United States could include warmer days and nights, increased total rainfall from heavy storms, increased tropical cyclone activity, sea level rise and increased drought conditions. An increase in the number of heat waves, periods of drought and sea level rise could result in changes in energy demand due to shifting populations and industry. Destruction caused by severe weather events such as hurricanes, tornadoes, severe thunderstorms and winter storms may result in lost operating revenues due to outages, property damage and other unexpected expenses.

We could become subject to litigation related to the purported impacts of GHG emissions. A number of legal actions have been filed against other electric utilities asserting public and private nuisance, trespass and negligence claims.

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 generation by PEC's hydroelectric plants, as well as our fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. 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 defer and amortize or collect from customers 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 with provisions for implementing an interim retail surcharge in the event future storms deplete the reserve and prudency reviews of storm costs by the FPSC. Storm reserve costs attributable to PEF's 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.

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 are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions. We are also impacted by the demand and competitive state of the wholesale market.

Our revenues, operating results and financial condition are impacted by customer growth and usage. Customer growth can be impacted by population growth as well as by economic factors, including but not limited to, job growth and housing market trends. The Utilities are impacted by the economic cycles of the customers we serve. As our service territories experience economic downturns, residential customer consumption patterns may change and our revenues may be negatively impacted. If our commercial and industrial customers experience economic downturns, their consumption of electricity may decline and our revenues can be negatively impacted. Like other parts of the United States, our service territories and business have been impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. Additionally, our customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income or individual energy conservation efforts.

Wholesale revenues fluctuate with regional demand, fuel prices and contracted capacity. Our wholesale profitability is dependent upon market conditions and our ability to renew or replace expiring wholesale contracts on favorable terms. Based on economic conditions in effect when wholesale contracts expire, the Utilities may not be successful in renewing or replacing expiring contracts.

Fluctuations in commodity prices or availability 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, nuclear fuel, electricity and other energy-related commodities, including emission allowances, 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 prevailing market prices. In such event, we might incur losses in addition to the amounts, if any, already paid to the counterparties.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Downgrades in our credit ratings could lead to additional collateral posting requirements. We continually monitor our derivative positions in relation to market price activity.

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;
- technological changes;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, nuclear fuel 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. The demand and prices for labor and materials are subject to volatility and may increase in the future. 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 emission allowance credits fluctuate. While 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 changes in the price of allowances could have a significant adverse financial impact on us and PEC and, consequently, on our results of operations and cash flows.

As a holding company with no revenue-generating operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily the Utilities; its commercial paper and bank facilities; and its ability to access the long-term debt and equity capital markets.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's senior unsecured debt and potentially funding a portion of the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. 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. Additionally, the Utilities could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from the Parent. Should the Utilities not be able to pay dividends or repay funds due to the Parent or if the Parent cannot access the commercial paper market, its bank facilities or the long-term debt and equity capital markets, the Parent's ability to pay principal, interest and dividends would be restricted. The Parent could change its existing common stock dividend policy based upon these and other business factors.

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 or pursue improvements 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, long-term debt and equity. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy will be adversely affected. Market disruptions or a downgrade of our credit ratings could increase our cost of borrowing and may adversely affect our ability to access the financial markets. If we cannot fund our expected capital expenditures and debt maturities through normal operations or by accessing capital markets, our business plans, financial condition, results of operations or cash flows may be adversely impacted. See discussion of our expected capital expenditures in MD&A – "Liquidity and Capital Resources – Capital Expenditures."

We issue commercial paper to meet short-term liquidity needs. When financial and economic conditions result in tightened short-term credit markets, coupled with corresponding volatility in commercial paper durations and interest rates, we evaluate other options for meeting our short-term liquidity needs, which may include borrowing from our revolving credit agreements (RCAs), issuing short-term notes, issuing long-term debt and/or issuing equity. In addition, if our short-term credit ratings are downgraded below Tier 2 (A-2/P-2/F2) we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets may be negatively impacted. In that case, we would evaluate other options for meeting our short-term liquidity needs as previously described. These alternative sources of liquidity may not be available or 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 or reductions in our cash flow 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. 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 that are not recorded on the Consolidated Balance Sheets.

As previously discussed, 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 or reductions in cash flow 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;
- 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.

Any reduction in our credit ratings below investment grade would likely increase our financing 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. Such circumstances could include, among others, increases in leverage, adverse changes in other financial metrics, and adverse regulatory outcomes. 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, may adversely affect our access to capital and could result in the posting of additional collateral for derivatives in a liability position, which could negatively impact our financial results and business plans. Any reduction in our credit ratings below investment grade could also result in collateral posting requirements for certain of our natural gas transportation contracts. 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.

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 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. Although a number of factors impact our funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning 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.

Impairment of goodwill could have a significant negative impact on our financial condition and results of operations.

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments, and goodwill impairment tests are performed at the utility segment level.

We calculate the fair value of our utility segments by considering various factors, including valuation studies based primarily on income and market approaches. The calculations in both approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. The estimated future cash flows are based on the utility segments' business plans that assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and renewal of certain contracts. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility segments could be significantly different in future periods, which could result in a future impairment charge to goodwill. Impairment of our recorded goodwill could result in volatility in our GAAP earnings and an increase in our leverage, which could trigger a downgrade of our credit ratings leading to higher borrowing costs and/or dilution through additional issuances of common stock. However, in the event of a goodwill impairment, we do not expect any such impairment to cause us to violate any financial or restrictive covenants contained in our indebtedness or other contractual arrangements.

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. 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.

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 steam, nuclear, combustion turbines, combined cycle, and hydroelectric resources, with a total summer generating capacity of 12,585 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2009, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)	Summer Net Capability[a] (in MW)
FOSSIL STEAM						
~~Asheville~~	~~Arden, N.C.~~	~~2~~	~~1964-1971~~	~~Coal~~	~~100~~	~~376~~
Cape Fear[b]	Moncure, N.C.	2	1956-1958	Coal	100	316
Lee[b]	Goldsboro, N.C.	3	1951-1962	Coal	100	397
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	727 [c]
Robinson	Hartsville, S.C.	1	1960	Coal	100	177
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.30 [d]	2,422 [c]
Sutton [b]	Wilmington, N.C.	3	1954-1972	Coal	100	604
Weatherspoon[b]	Lumberton, N.C.	3	1949-1952	Coal	100	171
	Total	19				5,190
NUCLEAR						
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,858 [c]
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900 [c]
Robinson	Hartsville, S.C.	1	1971	Uranium	100	724
	Total	4				3,482
COMBUSTION TURBINES						
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	324
Blewett	Lilesville, N.C.	4	1971	Oil	100	52
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	799
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	820
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	15
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100	61
Wayne County	Goldsboro, N.C.	5	2000-2009	Gas/Oil	100	863
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	131
	Total	42				3,152
COMBINED CYCLE						
Cape Fear	Moncure, N.C.	2	1969	Oil	100	66
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100	470
	Total	3				536
HYDRO						
Blewett	Lilesville, N.C.	6	1912	Water	100	22
Marshall	Marshall, N.C.	2	1910	Water	100	4
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100	87
Walters	Waterville, N.C.	3	1930	Water	100	112
	Total	15				225
TOTAL		83				12,585

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

(b) PEC has announced that it intends to permanently shut-down these units between 2013 and the end of 2017. See Item 1 – "PEC – Fuel and Purchased Power – Oil and Gas" regarding PEC's plans to build new generation fueled by natural gas.

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

(d) 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, 2009, including both the total generating capacity of 12,585 MW and the total firm contracts for purchased power of 1,309 MW, PEC had total capacity resources of approximately 13,894 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, 2009, 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 22,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 55 million kilovolt-ampere (kVA) in approximately 900 transformers. Distribution line transformers numbered approximately 538,000 with an aggregate capacity of approximately 24 million kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil steam, combustion turbine, combined cycle, and nuclear resources, with a total summer generating capacity of 10,013 MW. Of this total, joint owners own approximately 120 MW. At December 31, 2009, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability [a] (in MW)
FOSSIL STEAM						
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	1,011
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,267
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	131
	Total	9				3,409
COMBINED CYCLE						
Bartow	St. Petersburg, Fla.	1	2009	Gas/Oil	100	1,133 [b]
Hines	Bartow, Fla.	4	1999-2007	Gas/Oil	100	1,912
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	205
	Total	6				3,250
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	48
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	178
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	174
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	642
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	114
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	[c]	980 [d]
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	147
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,494
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	860 [d]
	Total	1				860
TOTAL		63				10,013

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

(b) This facility, which had a summer net capacity of 426 MW in 2008, was converted from fossil steam to combined cycle and returned to commercial operations in June 2009.

(c) PEF and Georgia Power Company are joint owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site. Georgia Power Company 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.

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

During 2009, including both the total generating capacity of 10,013 MW and the total firm contracts for purchased power of 1,847 MW, PEF had total capacity resources of approximately 11,860 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 Company are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City Unit P11. Georgia Power Company 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, 2009, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and approximately 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 54 million kVA in approximately 800 transformers. Distribution line transformers numbered approximately 390,000 with an aggregate capacity of approximately 20 million kVA.

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 AT FEBRUARY 22, 2010

Name	Age	Recent Business Experience
William D. Johnson	56	**Chairman, President and Chief Executive Officer, Progress Energy and Florida Progress,** October 2007 to present; **Chairman, PEC and PEF,** from November 2007 to present; President and Chief Operating Officer, Progress Energy, from January 2005 to October 2007; Group President, PEC, from January 2004 to October 2007; Executive Vice President, PEF, from November 2000 to November 2007; Executive Vice President, Florida Progress, from November 2000 to December 2003; and Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress, from 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, from January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, from 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, N.C. office of Hunton & Williams LLP where he specialized in the representation of utilities. He previously served as a law clerk to the Honorable J. Dickson Phillips Jr. of the U.S. Court of Appeals for the Fourth Circuit.

Jeffrey A. Corbett 50 **Senior Vice President, Energy Delivery, PEC,** January 2008 to present. Mr. Corbett oversees operations and services in the Carolinas, including engineering, distribution, construction, metering, power restoration, community relations and customer service. He previously served as Senior Vice President, Energy Delivery, PEF, from June 2006 to January 2008, 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. Mr. Corbett joined Progress Energy in 1999 and has served 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.

*Vincent M. Dolan 55 **President and Chief Executive Officer, PEF,** July 2009 to present. Mr. Dolan oversees all aspects of PEF's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Vice President – External Relations, PEF, from December 2006 to July 2009; Vice President – Regulatory & Customer Relations, PEF, from March 2005 to December 2006; and Vice President – Corporate Relations & Administrative Services, PEF, from April 2002 to March 2005. Mr. Dolan has been with PEF since 1986 in positions of increasing responsibility in the areas of operations, strategic development, customer services, and regulatory affairs. Prior to that, he was with Foster Wheeler Energy Corporation, an international engineering and manufacturing firm.

*Michael A. Lewis 47 **Senior Vice President, Energy Delivery, PEF,** January 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, Distribution, PEF, from August 2007 to January 2008, Vice President, Distribution Engineering & Operations, PEF, from December 2005 to August 2007, Vice President, Distribution Operations & Support, PEF, from April 2004 to December 2005 and Vice President, Coastal Region, PEF, from December 2000 to April 2004. Mr. Lewis has been with PEF in a number of engineering and management positions since 1986, including District Manager, Distribution Operations Manager in Pasco County, General Manager for the South Coastal region and Regional Vice President of both the North and South Coastal regions.

Jeffrey J. Lyash 48 **Executive Vice President, Corporate Development, Progress Energy,** July 2009 to present. In his role, Mr Lyash is responsible for Progress Energy's resource planning, program alternatives, and strategic asset construction. He previously served as President and Chief Executive Officer, PEF, from June 2006 to July 2009; Senior Vice President, PEF, from November 2003 to June 2006; and Vice President – Transmission in Energy Delivery, PEC, from January 2002 to October 2003.

Mr. Lyash joined Progress Energy (formerly CP&L) in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations. Before joining Progress Energy, Mr. Lyash worked with the U.S. Nuclear Regulatory Commission (NRC) in a number of capacities between 1984 and 1993

John R. McArthur	54	**Executive Vice President, Progress Energy,** September 2008 to present. In his various roles, Mr. McArthur is responsible for corporate and utility support functions, including Corporate Services, Corporate Communications, External Relations, Human Resources and Information Technology and Telecommunications. The compliance, legal and audit functions are also part of his group. He also serves as Corporate Secretary of Progress Energy, a position he has held since January 2004. Mr. McArthur is also Executive Vice President of PEC since September 2008, Executive Vice President of PEF since November 2008 and Executive Vice President of Florida Progress Corporation since January 2010. Mr. McArthur has been with Progress Energy in a number of roles since 2001, including General Counsel, Senior Vice President, Corporate Relations and Vice President, Public Affairs. Before joining Progress Energy, Mr. McArthur was a senior adviser to N.C. Governor Mike Easley, handling major policy initiatives as well as media and legal affairs. Previously, he handled state government affairs for General Electric Co. He also served as chief counsel in the N.C. Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Prior to that Mr. McArthur was a partner with the Raleigh, N.C. office of Hunton & Williams LLP and served as a law clerk to the Honorable Sam J. Ervin III of the U.S. Court of Appeals for the Fourth Circuit.
Mark F. Mulhern	50	**Senior Vice President and Chief Financial Officer, Progress Energy, PEC and PEF,** September 2008 to present. He previously served as Senior Vice President, Finance, PEC and PEF, from November 2007 to September 2008, and Senior Vice President, Finance, Progress Energy, from July 2007 to September 2008. Mr. Mulhern also served as President of Progress Ventures (the unregulated subsidiary of Progress Energy), from 2005 to 2008; Senior Vice President of Competitive Commercial Operations of Progress Ventures, from 2003 to 2005, Vice President, Strategic Planning of Progress Energy, from 2000 to 2003; Vice President and Treasurer of Progress Energy, from 1997 to 2000, and Vice President and Controller of Progress Energy, from 1996 to 1997. Before joining Progress Energy (formerly CP&L) in 1996, Mr. Mulhern was the Chief Financial Officer at Hydra Co Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at Price Waterhouse, serving a wide variety of manufacturing and service businesses.
James Scarola	53	**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 the Brunswick Nuclear Plant from October 2005 to December 2007. Mr. Scarola joined Progress Energy (formerly CP&L) in 1998, where he served as Vice President at the Harris Nuclear Power Plant until October 2005. Mr. Scarola entered the nuclear power field in 1978 as a design engineer and has held positions in construction, start-up testing, maintenance, engineering and operations. He was the Plant General Manager at the St. Lucie Nuclear Plant with Florida Power & Light Company prior to joining Progress Energy.

Frank A. Schiller 48 **Senior Vice President, Compliance and General Counsel, Progress Energy,** January 2009 to present. Mr. Schiller is responsible for Progress Energy's legal, regulatory, compliance, audit and corporate governance functions. He serves as Progress Energy's chief compliance officer and chairs Progress Energy's Ethics Committee. Mr. Schiller joined Progress Energy in 1997 and previously served as Vice President, Legal, from December 2000 to December 2008; Director – Legal Services, from January 2000 to December 2000; and Associate General Counsel, from December 1997 to January 2000.

Before joining Progress Energy, Mr. Schiller was Senior Counsel at Virginia Electric and Power Company. Previously, he was a partner with the Raleigh, N.C., office of Hunton & Williams LLP.

Paula J. Sims 48 **Senior Vice President, Power Operations, PEC and PEF,** July 2007 to present. Ms. Sims oversees fossil generation, new generation and transmission construction, environmental compliance, non-nuclear fuel procurement and transportation, purchased power and excess generation sales. In addition, she is responsible for leading Progress Energy's enterprise-wide Continuous Business Excellence efforts. Ms. Sims previously served as Senior Vice President, Regulated Services from January 2006 to July 2007; Vice President, Fossil Fuel Generation of Progress Energy and PEF, from January 2006 to April 2006; Vice President, Regulated Fuels of Progress Energy, from December 2004 to December 2005; Chief Operating Officer of Progress Fuels Corporation, from February 2002 to December 2004; and Vice President, Business Operations & Strategic Planning of Progress Fuels Corporation, from June 2001 to February 2002.

Before joining Progress Energy in 1999, Ms. Sims was with General Electric, where she served in a number of management and operations positions for over 15 years.

Jeffrey M. Stone 48 **Chief Accounting Officer and Controller, Progress Energy and Florida Progress,** June 2005 to present; Chief Accounting Officer, PEC and PEF, from June 2005 and November 2005, respectively, to present; and Vice President and Controller, Progress Energy Service Company, LLC, from 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; and 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	49	**President and Chief Executive Officer, PEC,** July 2007 to present. Mr. Yates oversees all aspects of PEC's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President, PEC, from January 2005 to July 2007, where he was responsible for overseeing the four operational and customer service regions in the Carolinas, as well as the distribution function. He served PEC as Vice President – Transmission, from November 2003 to December 2004 and as Vice President – Fossil Generation, from November 1998 to November 2003 Before joining Progress Energy (formerly CP&L) in 1998, Mr. Yates was with PECO Energy for over 16 years in several line operations and management positions.

*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 cash dividends declared per share are as follows:

	High	Low	Dividends Declared
2009			
First Quarter	**$40.85**	**$31.35**	**$0.620**
Second Quarter	**38.20**	**33.50**	**0.620**
Third Quarter	**40.05**	**35.97**	**0.620**
Fourth Quarter	**42.20**	**36.67**	**0.620**
2008			
First Quarter	$49.16	$40.54	$0.615
Second Quarter	43.58	41.00	0.615
Third Quarter	45.52	40.11	0.615
Fourth Quarter	45.60	32.60	0.620

The December 31 closing price of our Common Stock was $41.01 for 2009 and $39.85 for 2008. At February 22, 2010, we had 53,922 holders of record of Common Stock.

Progress Energy expects to continue its policy of paying regular cash dividends; however, dividends are subject to declaration by the Board of Directors and the existing common stock dividend policy could change based upon business factors, including future earnings, capital requirements, and financial condition.

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 9 and 11B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2010 Annual Meeting of Shareholders.

(a) Recent Sales of Unregistered Securities; Use of Proceeds from Registered Securities.

RESTRICTED STOCK UNIT AWARD PAYOUTS:

(1) Securities Delivered. On October 5, 2009, 1,772 shares, of our common stock were delivered to a former employee pursuant to the terms of the Progress Energy 2002 and 2007 Equity Incentive Plans (individually and collectively, the "EIP,"), which have been approved by Progress Energy's shareholders. Additionally, on November 27, 2009, 3,142 shares of our common stock were delivered to the estate of a former employee pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(2) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(3) Consideration. The restricted stock unit awards were granted to provide an incentive to the former and current 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.

(4) 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:

(1) Securities Delivered. On November 27, 2009, 7,650 shares of our common stock were delivered to the estate of a former employee pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(2) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(3) Consideration. The performance share awards were granted to provide an incentive to the former employee to exert his utmost efforts on our behalf and thus enhance our performance while aligning the employee's interests with those of our shareholders.

(4) 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.

(b) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

Issuer purchases of equity securities for fourth quarter of 2009 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1) (2) (3) (4)	(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	787,147	$37.9369	N/A	N/A
November 1 – November 30	95,409	37.2923	N/A	N/A
December 1 – December 31	25,700	41.2084	N/A	N/A
Total	908,256	$37.9618	N/A	N/A

(1) At December 31, 2009, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.
(2) The plan administrator purchased 667,277 shares of our common stock in open-market transactions to meet share delivery obligations under the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) (See Note 9B).
(3) The plan administrator purchased 240,250 shares of our common stock in open-market transactions to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation (See Note 9B).
(4) During the fourth quarter of 2009, 729 shares of our common stock were withheld to pay taxes due upon the payout of certain Restricted Stock Unit awards and Performance Share Sub-Plan awards pursuant to the terms of our 2002 and 2007 Equity Incentive Plans.

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. During 2009 and 2007, PEC paid 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. During 2008, PEC paid no dividends to the Parent. PEC has provisions restricting dividends in certain circumstances (See Notes 9 and 11). 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 2009, 2008 and 2007, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 9 and 11). 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)	**2009**	2008[a]	2007[a]	2006[a]	2005[a]
OPERATING RESULTS					
Operating revenues	**$9,885**	$9,167	$9,153	$8,724	$7,948
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**840**	778	702	567	527
Net income	**761**	836	496	620	668
Net income attributable to controlling interests	**757**	830	504	571	697
PER SHARE DATA[b]					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$2.99**	$2.95	$2.70	$2.19	$2.10
Net income attributable to controlling interests	**2.71**	3.17	1.96	2.27	2.80
ASSETS	**$31,236**	$29,873	$26,338	$25,832	$27,083
CAPITALIZATION AND DEBT					
Common stock equity	**$9,449**	$8,687	$8,395	$8,259	$8,011
Noncontrolling interests	**6**	6	84	10	36
Preferred stock of subsidiaries	**93**	93	93	93	93
Long-term debt, net[c]	**12,051**	10,659	8,737	8,835	10,446
Current portion of long-term debt	**406**	–	877	324	513
Short-term debt	**140**	1,050	201	–	175
Capital lease obligations	**231**	239	247	72	18
Total capitalization and debt	**$22,376**	$20,734	$18,634	$17,593	$19,292
Dividends declared per common share	**$2.480**	$2.465	$2.445	$2.425	$2.375

(a) Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

(b) Balances have been restated for the adoption of new accounting guidance, which redefined which securities and non-vested share-based compensation awards are considered to participate in our current earnings (See Note 2).

(c) Includes long-term debt to affiliated trust of $272 million at December 31, 2009 and 2008, $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005 (See Note 23).

PEC

	Years Ended December 31				
(in millions)	**2009**	2008[(a)]	2007[(a)]	2006[(a)]	2005[(a)]
OPERATING RESULTS					
Operating revenues	**$4,627**	$4,429	$4,385	$4,086	$3,991
Net income	**514**	534	501	457	493
Net income attributable to controlling interests	**516**	534	501	457	493
Net income available to parent	**513**	531	498	454	490
ASSETS	**$13,502**	$13,165	$11,955	$11,999	$11,471
CAPITALIZATION AND DEBT					
Common stock equity	**$4,657**	$4,301	$3,752	$3,363	$3,091
Noncontrolling interests	**3**	4	4	4	5
~~Preferred stock~~	~~**59**~~	~~59~~	~~59~~	~~59~~	~~59~~
Long-term debt, net	**3,703**	3,509	3,183	3,470	3,667
Current portion of long-term debt	**6**	–	300	200	–
Short-term debt[(b)]	–	110	154	–	84
Capital lease obligations	**15**	16	17	18	18
Total capitalization and debt	**$8,443**	$7,999	$7,469	$7,114	$6,924

(a) Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

(b) Includes notes payable to affiliated companies, related to the money pool program, of $–, $154 million and $11 million at December 31, 2008, 2007 and 2005, respectively.

PEF

The information called for by Item 6 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

The following combined Management's Discussion and Analysis 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.

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 includes financial information prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), as well as certain non-GAAP financial measures, "Ongoing Earnings" and "Base Revenues," discussed below. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The non-GAAP financial measures should be viewed as a supplement to and not a substitute for financial measures presented in accordance with GAAP. Non-GAAP measures as presented herein may not be comparable to similarly titled measures used by other companies.

MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements. Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments are PEC and PEF, and their primary operations are the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The "Corporate and Other" segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative requirements as a separate reportable business segment.

STRATEGY

We are an integrated energy company primarily focused on the end-use electricity markets. We own two electric utilities that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to attractive wholesale markets in the eastern United States. The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. 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 have a strong track record of meeting our financial commitments and delivering operational excellence. We have maintained liquidity and financial stability and sustained our dividend rate during the current economic downturn, and we believe that we have good prospects for growth once the economy begins to recover. An improving national economy may lead to greater mobility for homeowners around the country and a return of migration to the Southeast region that is more consistent with historical levels. The utility industry, as a whole, however, faces significant cost pressures and, in the near-term, lower retail electricity sales. In addition, current economic conditions and anticipated higher expenditures (including for environmental compliance, renewable energy standards compliance and new generation and transmission facilities) may subject us to an even higher level of scrutiny from regulators and lead to a more uncertain regulatory environment. We anticipate the need to prepare for a different kind of energy future – one that would include, among other things, reducing carbon emissions and using emerging technologies such as the Smart Grid and electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework to prepare for this new energy future. Additional information about the strategy, including updates on implementation, is included in "Strategic Initiatives" below.

To manage the challenges of the present and prepare for the future, management's priority focus areas for 2010 and beyond are as follows:

- Financial Performance
- Operational Performance
- Organizational Effectiveness
- Regulation and Public Policy
- Strategic Initiatives

The first two priorities are core elements of managing our business. The next two priorities will help enable what we can accomplish in the future. The last priority involves making the right investments to create a strong energy future for Progress Energy and our customers.

FINANCIAL AND OPERATIONAL PERFORMANCE

Effectively managing expenses, deploying capital and enhancing our margin are critical to achieving sustainable earnings growth and attractive long-term returns for our shareholders. We have instituted throughout our organization systematic approaches to achieve sustainable cost savings through enhanced efficiency and productivity. These ongoing cost management initiatives – along with short-term expense management – have enabled us to offset some of the impact of the economic downturn and cost pressures and should yield long-term operations and maintenance (O&M) expense savings and effective capital management. Also, we recognize that our shareholders strongly value our dividend and that it is an integral part of our total shareholder return proposition. Our long-term goal is to achieve a 70 to 75 percent dividend payout ratio, and we are committed to managing the company such that we reach this target while maintaining an attractive, sustainable dividend rate.

Our financial performance depends on the successful operation of the Utilities' electric generating and distribution facilities and reliable delivery of electric service to our customers. Consequently, we strive to excel in safety, operational performance and customer satisfaction. We also focus on rigorous project management in executing our capital program, including large-scale capital projects such as construction of new generating facilities, modernization of existing facilities and environmental compliance as well as programs such as demand-side management (DSM).

Another operational priority is a fleet alignment initiative to strengthen the Utilities' nuclear performance in safely and reliably producing electricity while meeting the highest standards of environmental protection in the most efficient manner. The multi-year initiative implements a new business model for our five nuclear units and is based on industry benchmarking that coordinated, collaborative and standardized operations achieves and sustains a higher level of performance than would be possible if each unit operated autonomously. The goals of the initiative are, among other things, to establish a common vision and set of core values; facilitate common procedures across the fleet to accommodate shared resources and industry best practices; and establish a strong performance-monitoring system that provides feedback to management.

ORGANIZATIONAL EFFECTIVENESS

With our managers and supervisors at all levels, we emphasize demonstrating the leadership behaviors that fully engage our workforce and optimize their performance in executing our strategy. We strive to cultivate an inclusive work environment in which we treat everyone with respect and hold each other to high standards. In addition, we are implementing long-term workforce strategies to prepare for our changing needs and an aging workforce. Our workforce strategy includes recruiting, training and retaining a skilled, diverse workforce that reflects the communities we serve.

REGULATION AND PUBLIC POLICY

PEC and PEF are regulated by the state utility commissions in their state jurisdictions. Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of prudent expenses and a fair return on utility investments. Our business plans include the assumption that the respective public utility commissions will provide reasonable recovery. In 2009, PEC received approval for its coal-to-gas fleet modernization plan discussed in "Strategic Initiatives" as well as multiple DSM, renewable energy and energy-efficiency filings. Also in 2009, PEF successfully sought interim and limited rate relief and nuclear cost recovery in Florida. However, in response to a 2009 base rate case PEF filed with the Florida Public Service Commission (FPSC), in January 2010, the FPSC decided to grant PEF no increase in base rates above what was previously awarded in 2009 for the repowered Bartow Plant (approximately $132 million annual revenue requirements). The FPSC's decision was predicated on its desire to hold down rates. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. We are currently reviewing our regulatory options in Florida. We believe that the FPSC's regulatory action was strongly influenced by the current economic downturn. In a long-term view of Florida's regulatory environment, we believe that as the economy improves, the need to provide for Florida's energy future will have a stronger influence in the FPSC's decision-making process. Consequently, we do not believe the January 2010 decision represents a permanent change to the regulatory environment in Florida.

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Changes in federal and state regulation are currently under consideration for, among others, greenhouse gases (GHG) such as carbon dioxide (CO_2), coal combustion products, mercury and particulate matter. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. 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. However, we anticipate that it could result in significant rate increases over time to recover the compliance costs.

We are dedicated to seeking achievable, affordable climate and energy policies. We evaluate public policy proposals and actively promote initiatives that are achievable but manage the long-term costs to our customers.

STRATEGIC INITIATIVES

Our balanced solution strategy is intended to deploy capital effectively to meet future customer needs and emerging public policies while achieving our financial objectives. It is a three-pronged strategy that focuses on energy efficiency, alternative energy and state-of-the-art power generation. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms implemented by our state jurisdictions. Updates on our implementation of this strategy are discussed below.

First, we are expanding and enhancing our DSM, energy-efficiency and energy conservation programs. We have implemented expanded energy-efficiency programs to our customers and continue to pursue additional initiatives. Federal law enacted in 2009 contains provisions promoting energy efficiency and renewable energy and we have been notified of our selection for Smart Grid grant negotiations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. While this currently represents a small percentage of our total capacity, we will continue to pursue additional contracts for these and other alternative energy sources.

Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating modernization of existing coal plants and the best new generation options, including advanced design nuclear technology and gas-fired combined cycle and combustion turbines. In 2009, we completed the repowering of PEF's Bartow Plant, construction of a new 157-MW combustion turbine at PEC and the installation of pollution control equipment (or scrubbers) on PEF's coal-fired unit, Crystal River Unit No. 5 (CR5), and PEC's Mayo Plant. We also received approval to construct a 600-MW combined cycle dual-fuel facility and a 950-MW combined cycle natural gas-fueled facility at PEC, which are expected to come online in 2011 and 2013, respectively. PEC has filed for approval to construct a 620-MW natural gas-fueled facility. In 2009, we also announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions.

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. In 2008, the Utilities each filed a combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy).

We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions, as well as existing state legislative policy that is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a COL remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In light of a regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan with respect to Levy.

In summary, we are effectively dealing with today's challenges while taking steps to create long-term value for our customers and shareholders.

RESULTS OF OPERATIONS

In this section, we provide analysis and discussion of earnings and the factors affecting earnings on both a GAAP and non-GAAP basis. We introduce our results of operations in an overview section followed by a more detailed analysis and discussion by business segment.

A reconciliation of "Ongoing Earnings" to GAAP net income attributable to controlling interests is below, followed by an explanation of our non-GAAP financial measurement, "Ongoing Earnings."

For the year ended December 31, 2009 (in millions, except per share data)	**PEC**	**PEF**	**Corporate and Other**	**Total**	**Per Share**
Ongoing Earnings	**$540**	**$460**	**$(154)**	**$846**	**$3.03**
CVO mark-to-market	**–**	**–**	**19**	**19**	**0.07**
Impairment, net of tax[a]	**–**	**–**	**(2)**	**(2)**	**(0.01)**
Plant retirement charge, net of tax[a]	**(17)**	**–**	**–**	**(17)**	**(0.06)**
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax[a]	**(10)**	**–**	**–**	**(10)**	**(0.04)**
Discontinued operations attributable to controlling interests, net of tax	**–**	**–**	**(79)**	**(79)**	**(0.28)**
Net income (loss) attributable to controlling interests[b]	**$513**	**$460**	**$(216)**	**$757**	**$2.71**

For the year ended December 31, 2008 (in millions, except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Ongoing Earnings	$531	$383	$(138)	$776	$2.96
Valuation allowance and related net operating loss carry forward	–	–	(3)	(3)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	57	57	0.22
Net income (loss) attributable to controlling interests[b]	$531	$383	$(84)	$830	$3.17

For the year ended December 31, 2007 (in millions, except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Ongoing Earnings	$498	$315	$(118)	$695	$2.71
CVO mark-to-market	–	–	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	(189)	(189)	(0.74)
Net income (loss) attributable to controlling interests[b]	$498	$315	$(309)	$504	$1.96

(a) Calculated using assumed tax rate of 40 percent

(b) Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $(3) million and $(2) million at PEC and PEF, respectively.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings. We compute Ongoing Earnings as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Historically, Ongoing Earnings for our reportable segments, which are PEC and PEF, have been consistent with the most comparable GAAP measure, net income attributable to controlling interests. In 2009, PEC recorded charges that management determined should be excluded from PEC's Ongoing Earnings. The charges were related to its planned retirement of certain coal-fired generating units prior to the end of their useful lives and a cumulative prior period adjustment related to certain employee life insurance benefits. The prior period adjustment, which was recorded in the fourth quarter of 2009, is not material to previously issued or current period financial statements. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP.

OVERVIEW

FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

For the year ended December 31, 2009, our net income attributable to controlling interests was $757 million, or $2.71 per share, compared to $830 million, or $3.17 per share, for the same period in 2008. The decrease as compared to prior year was due primarily to:

- unfavorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- unfavorable net retail customer growth and usage at the Utilities;
- higher interest expense; and
- higher base depreciation and amortization at the Utilities.

Partially offsetting these items were:

- net impact of returns earned on higher levels of nuclear and environmental cost recovery clause (ECRC) assets at PEF;
- favorable impact of interim and limited base rate relief at PEF;
- depreciation and amortization expense recognized in 2008 at PEC related to North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization expense and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets; and
- favorable weather at the Utilities.

For the year ended December 31, 2008, our net income attributable to controlling interests was $830 million, or $3.17 per share, compared to $504 million, or $1.96 per share, for the same period in 2007. The increase in 2008 as compared to 2007 was due primarily to:

- favorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- favorable allowance for funds used during construction (AFUDC) at the Utilities;
- increased retail base rates at PEF;
- higher wholesale revenues at PEF,
- lower purchased power capacity costs at PEC due to the expiration of a power buyback agreement; and
- favorable net retail customer growth and usage at PEC.

Partially offsetting these items were:

- higher interest expense at PEF;
- higher income tax expense due to the benefit from the closure of certain federal tax years and positions in 2007;
- unfavorable net retail customer growth and usage at PEF;
- unfavorable weather at PEC;
- higher investment losses of certain employee benefit trusts at PEF and Corporate and Other resulting from the decline in market conditions; and
- higher depreciation and amortization expense at PEF excluding prior year recoverable storm amortization at PEF.

PROGRESS ENERGY CAROLINAS

PEC contributed net income available to parent totaling $513 million, $531 million and $498 million in 2009, 2008 and 2007, respectively. The decrease in net income available to parent for 2009 as compared to 2008 was primarily due to unfavorable net retail customer growth and usage, coal plant retirement charges, higher base depreciation and amortization expense and a cumulative prior period adjustment related to certain employee life insurance benefits, partially offset by Clean Smokestacks Act amortization and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the favorable impact of weather. PEC contributed Ongoing Earnings of $540 million in 2009. There were no Ongoing Earnings adjustments in 2008 and 2007. The 2009 Ongoing Earnings adjustments to net income available to parent were due to PEC recording a $17 million charge, net of tax, for the impact of PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives and recording a $10 million charge, net of tax, for a cumulative prior period adjustment related to certain employee life insurance benefits. Management does not consider these charges to be representative of PEC's fundamental core earnings and excluded these charges in computing PEC's Ongoing Earnings.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to lower purchased power capacity costs due to the expiration of a power buyback agreement, favorable AFUDC and favorable net retail customer growth and usage, partially offset by the unfavorable impact of weather and lower excess generation revenues.

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEC consider Base Revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power expenses and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the return on asset component of DSM, energy-efficiency and renewable energy clause revenues. We and PEC have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, follows:

(in millions) Customer Class	2009	% Change	2008	% Change	2007
Residential	**$1,179**	1.6	$1,160	(1.0)	$1,172
Commercial	**741**	(0.9)	748	0.4	745
Industrial	**374**	(10.1)	416	2.0	408
Governmental	**62**	(3.1)	64	4.9	61
Unbilled	**5**	–	8	–	(1)
Total retail base revenues	**2,361**	(1.5)	2,396	0.5	2,385
Wholesale base revenues	**310**	–	310	(12.7)	355
Total Base Revenues	**2,671**	(1.3)	2,706	(1.2)	2,740
Clause recoverable regulatory returns	**6**	–	–	–	–
Miscellaneous	**114**	11.8	102	5.2	97
Fuel and other pass-through revenues	**1,836**	–	1,621	–	1,548
Total operating revenues	**$4,627**	4.5	$4,429	1.0	$4,385

PEC's total retail base revenues were $2.361 billion and $2.396 billion for 2009 and 2008, respectively. The $35 million decrease in revenues was due primarily to the $58 million unfavorable impact of net retail customer growth and usage, partially offset by the $23 million favorable impact of weather. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 14,000 increase in the average number of customers for 2009 compared to 2008. However, PEC's rate of residential growth has declined as PEC's average number of customers increased a net 24,000 customers for 2008 compared to 2007. The favorable impact of weather was driven by higher heating and cooling degree days than 2008 of 3 percent and 5 percent, respectively. Additionally, cooling degree days were 6 percent higher than normal in 2009.

PEC's miscellaneous revenues increased $12 million in 2009 primarily due to higher transmission revenues.

PEC's total retail base revenues were $2.396 billion and $2.385 billion for 2008 and 2007, respectively. The $11 million increase in revenues was due primarily to the $34 million favorable impact of net retail customer growth and usage, partially offset by the $28 million unfavorable impact of weather. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal.

PEC's wholesale base revenues were $310 million and $355 million for 2008 and 2007, respectively. The $45 million lower wholesale base revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers.

PEC's electric energy sales in kilowatt-hours (kWh) and the percentage change by year and by customer class were as follows:

(in millions of kWh) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**17,117**	0.7	17,000	(1.2)	17,200
Commercial	**13,639**	(2.2)	13,941	(0.6)	14,032
Industrial	**10,368**	(9.0)	11,388	(4.3)	11,901
Governmental	**1,497**	2.1	1,466	1.9	1,438
Unbilled	**360**	–	(8)	–	(55)
Total retail kWh sales	**42,981**	(1.8)	43,787	(1.6)	44,516
Wholesale	**13,966**	(2.5)	14,329	(6.4)	15,309
Total kWh sales	**56,947**	(2.0)	58,116	(2.9)	59,825

The decrease in retail kWh sales in 2009 was primarily due to a decrease in average usage per retail customer. PEC's industrial kWh sales have decreased 9.0 percent from 2008, primarily due to continued reductions in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a continued downturn in the lumber and building materials segment as a result of declines in construction. Many of the manufacturers in PEC's service territory have been adversely impacted by the economic conditions, and we expect a relatively slow recovery in industrial sales once the economy begins to recover.

Wholesale kWh sales decreased for 2009 primarily due to decreased excess generation sales resulting from unfavorable market dynamics.

Industrial electric energy sales decreased in 2008 compared to 2007, primarily due to downturns in textile manufacturing and lumber and building materials segment as previously discussed.

PEC has experienced a decline in its retail and wholesale kWh sales due to the economic conditions in the United States. We cannot predict how long these conditions may last or the extent to which they may impact revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

<u>Fuel and Purchased Power</u>

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 applicable portions 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 $1.909 billion for 2009, which represents a $217 million increase compared to 2008. Fuel used in electric generation increased $334 million to $1.680 billion primarily due to $248 million higher deferred fuel expense and the $86 million net impact of higher fuel costs. The increase in deferred fuel expense was primarily due to the implementation of new fuel rates in North Carolina. The higher fuel costs were primarily due to higher coal prices. Purchased power expense decreased $117 million to $229 million compared to prior year. The decrease was primarily due to lower market purchases of $85 million and lower co-generation of $43 million primarily due to lower system requirements. See "PEC – Fuel and Purchased Power" in Item 1, "Business," for a summary of average fuel costs

Fuel and purchased power expenses were $1.692 billion for 2008, which represents a $9 million increase compared to 2007. Purchased power expense increased $44 million to $346 million compared to 2007. The increase was primarily due to increased economical purchases in 2008 of $78 million, partially offset by the $38 million impact from the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Fuel used in electric generation decreased $35 million to $1.346 billion primarily due to a $116 million decrease in deferred fuel expense, partially offset by increased fuel costs of $81 million. The decrease in deferred fuel expense was primarily driven by a $64 million impact from the implementation of state legislation that expanded the definition of the traditional fuel clause to include costs of commodities such as ammonia and limestone used in emissions control technologies (reagents), transmission charges and non-capacity-related costs of purchases and a $49 million impact related to under-recovered fuel costs. Deferred fuel expense was higher in 2007 primarily due to the collection of fuel costs from customers that had been previously under-recovered. The increase in fuel costs of $81 million was primarily due to an increase in coal prices, partially offset by the impacts of lower system requirements and a change in the generation mix.

Operation and Maintenance

O&M expense was $1.072 billion for 2009, which represents a $42 million increase compared to 2008. This increase was primarily due to coal plant retirement charges of $28 million, higher pension and benefit costs of $12 million and storm costs of $9 million, partially offset by lower emission allowance expense of $13 million resulting from lower system requirements, changes in generation mix and sales of nitrogen oxide (NOx) allowances. PEC recognized coal plant retirement charges ($17 million, net of tax) for the impact of the decision to retire 11 coal-fired units prior to the end of their useful lives (See "Future Liquidity and Capital Resources – PEC Other Matters" and "Other Matters – Energy Demand"). Management determined that such charges should be an exclusion from PEC's Ongoing Earnings.

O&M expense was $1.030 billion for 2008, which represents a $6 million increase compared to 2007. This increase was driven primarily by a $33 million increase in nuclear expenses, of which $18 million relates to refurbishments, preventive maintenance and incremental outage expenses at Brunswick Nuclear Plant (Brunswick). Additionally, O&M increased due to a $7 million increase in estimated environmental remediation expenses (See Note 21A), partially offset by $19 million lower employee benefits and $16 million lower nuclear plant outage and maintenance costs. The decrease in employee benefits was primarily due to the 2007 impact from changes in stock-based compensation plans and higher relative employee incentive goal achievement. The decrease in nuclear plant outage and maintenance costs was primarily due to two nuclear refueling and maintenance outages in 2008 compared to three in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $470 million for 2009, which represents a $48 million decrease compared to 2008. This decrease was primarily attributable to the $52 million of depreciation associated with the accelerated cost-recovery program for nuclear generating assets recognized during 2008 (See Note 7B) and the $15 million of Clean Smokestacks Act amortization recognized in 2008, partially offset by the $21 million impact of depreciable asset base increases. The North Carolina jurisdictional aggregate minimum amount of accelerated cost recovery has been met, and the South Carolina jurisdictional obligation was terminated by the

Public Service Commission of South Carolina (SCPSC). PEC does not anticipate recording additional accelerated depreciation in the North Carolina jurisdiction, but will record depreciation over the remaining useful lives of the assets. In accordance with a regulatory order, PEC ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful lives of the assets (See Note 7B).

Depreciation, amortization and accretion expense was $518 million for 2008, which represents a $1 million decrease compared to 2007. This decrease was primarily attributable to $19 million lower Clean Smokestacks Act amortization, $8 million lower GridSouth Transco, LLC (GridSouth) amortization and $3 million lower storm deferral amortization, partially offset by $15 million higher depreciation associated with the accelerated cost-recovery program for nuclear generating assets and the $15 million impact of depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $210 million, $198 million and $192 million in 2009, 2008 and 2007, respectively. The $12 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts taxes due to higher operating revenues and higher property tax rates. 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.

Total Other Income, Net

Total other income, net was $20 million for 2009, which represents a $23 million decrease compared to 2008. This decrease was primarily due to a cumulative prior period adjustment related to certain employee life insurance benefits and lower interest income resulting from lower average eligible deferred fuel balances. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net by $16 million and decreased net income available to parent by $10 million. The prior period adjustment is not material to previously issued or current period financial statements. Management determined that the adjustment should be an exclusion from PEC's Ongoing Earnings.

Total other income, net was $43 million for 2008, which represents a $6 million increase compared to 2007. This increase was primarily due to $17 million favorable AFUDC equity related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs, partially offset by $9 million lower interest income resulting from lower average eligible deferred fuel balances and lower temporary investment balances.

Total Interest Charges, Net

Total interest charges, net was $195 million for 2009, which represents a $12 million decrease compared to 2008. This decrease was primarily due to lower interest rates on variable rate debt, partially offset by higher interest as a result of higher average debt outstanding.

Total interest charges, net was $207 million for 2008, which represents a $3 million decrease compared to 2007. This decrease was primarily due to the $7 million favorable AFUDC debt related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs and the $4 million impact of a decrease in average long-term debt, offset by an $11 million interest benefit resulting from the resolution of tax matters in 2007.

Income Tax Expense

Income tax expense was $277 million, $298 million and $295 million in 2009, 2008 and 2007, respectively. The $21 million income tax expense decrease in 2009 compared to 2008 was primarily due to the impact of lower pre-tax income and the $5 million favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified nuclear decommissioning trusts (NDTs) to qualified NDTs. The $3 million income tax expense increase in 2008 compared to 2007 was primarily due to the $14 million impact of higher pre-tax income and the $5 million impact related to the deduction for domestic production activities, partially offset by the $7 million tax impact of employee stock-based benefits and the $7 million impact of the increase in AFUDC equity previously discussed. AFUDC equity is excluded from the calculation of income tax expense.

PROGRESS ENERGY FLORIDA

PEF contributed net income available to parent and Ongoing Earnings totaling $460 million, $383 million and $315 million in 2009, 2008 and 2007, respectively. The increase in net income available to parent for 2009 as compared to 2008 was primarily due to the higher net impact of returns earned on higher levels of nuclear and ECRC assets to be recovered through respective cost-recovery clauses, the favorable impact of interim and limited base rate relief (See Note 7C) and the favorable impact of weather, partially offset by the unfavorable impact of retail customer growth and usage, higher base depreciation and amortization expense, and higher O&M.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to favorable AFUDC, increased retail base rates and higher wholesale revenues, partially offset by higher interest expense, unfavorable net retail customer growth and usage, higher depreciation and amortization expense excluding recoverable storm amortization, and higher investment losses of certain employee benefit trusts.

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEF consider Base Revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and ECRC revenues. We and PEF have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, follows:

(in millions) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**$946**	5.9	$893	3.4	$864
Commercial	**340**	3.7	328	6.8	307
Industrial	**72**	(5.3)	76	5.6	72
Governmental	**87**	6.1	82	5.1	78
Unbilled	**9**	–	(1)	–	1
Total retail base revenues	**1,454**	5.5	1,378	4.2	1,322
Wholesale base revenues	**207**	5.1	197	33.1	148
Total Base Revenues	**1,661**	5.5	1,575	7.1	1,470
Clause recoverable regulatory returns	**87**	690.9	11	450.0	2
Miscellaneous	**189**	6.2	178	4.7	170
Fuel and other pass-through revenues	**3,314**	–	2,967	–	3,107
Total operating revenues	**$5,251**	11.0	$4,731	(0.4)	$4,749

PEF's total retail base revenues were $1.454 billion and $1.378 billion for 2009 and 2008, respectively. The $76 million increase was primarily due to the $79 million favorable impact of interim and limited base rate relief and the $36 million favorable impact of weather, partially offset by the $41 million unfavorable impact of retail customer growth and usage. The interim and limited base rate relief was approved by the FPSC effective July 1, 2009, as discussed in Note 7C. Of the $79 million interim and limited base rate relief, $7 million related to interim rate relief, which was in effect for only 2009, and $72 million related to limited rate relief, which will continue in accordance with the base rate proceeding with an annual revenue requirement of $132 million. The favorable impact of weather was primarily driven by 14 percent higher heating degree days than 2008 and 6 percent higher cooling degree days than 2008. Heating degree days were 4 percent lower than normal in 2009 and 16 percent lower than normal in

2008. In addition to lower average usage per customer, PEF's average number of customers for 2009, compared to 2008, decreased a net 8,000 customers and had no change in customers for 2008, compared to 2007.

PEF's clause recoverable regulatory returns were $87 million and $11 million for 2009 and 2008, respectively. The $76 million higher revenues related to nuclear cost recovery and ECRC assets of $61 million and $15 million, respectively. As a result of an FPSC regulatory order effective in January 2009, PEF is allowed to earn returns on certain costs related to nuclear construction, as discussed in Note 7C. We anticipate higher returns on ECRC assets in 2010 due to placing approximately $790 million of Clean Air Interstate Rule (CAIR) projects into service in late 2009. However, we do not anticipate a significant change in returns on nuclear cost-recovery assets in 2010 related to Levy.

PEF's total retail base revenues were $1.378 billion and $1.322 billion for 2008 and 2007, respectively. The $56 million increase was primarily due to $90 million of base rate increases, partially offset by the $32 million impact of unfavorable net retail customer growth and usage. The increase in base rates was due to $53 million from Hines 4 being placed in service and the $37 million transfer of Hines 2 cost recovery from the fuel clause to base rates. These base rate changes occurred in accordance with PEF's 2005 base rate settlement agreement.

PEF's wholesale base revenues of $197 million and $148 million for 2008 and 2007, respectively, increased $49 million. The increase was primarily due to several new and amended contracts.

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

(in millions of kWh) Customer Class	2009	% Change	2008	% Change	2007
Residential	**19,399**	0.4	19,328	(2.9)	19,912
Commercial	**11,884**	(2.1)	12,139	(0.4)	12,183
Industrial	**3,285**	(13.2)	3,786	(0.9)	3,820
Governmental	**3,256**	(1.4)	3,302	(1.9)	3,367
Unbilled	**131**	–	(99)	–	(6)
Total retail kWh sales	**37,955**	(1.3)	38,456	(2.1)	39,276
Wholesale	**3,835**	(43.1)	6,734	11.8	6,024
Total kWh sales	**41,790**	(7.5)	45,190	(0.2)	45,300

Wholesale base revenues increased in 2009, despite decreased wholesale kWh sales in 2009, primarily due to committed capacity revenues. The wholesale kWh sales decreased primarily due to market conditions in which wholesale customers fulfilled a portion of their system requirements from other sources. Many of the new and amended capacity contracts entered into in 2008 expired by the end of 2009. Given the current economic conditions discussed below, PEF does not believe it is likely to replace these wholesale contracts in 2010.

Retail base revenues increased in 2009, despite a decrease in kWh sales for the same period, primarily due to the impact of interim and limited base rate relief approved by the FPSC in 2009 (See Note 7C). Retail base revenues increased in 2008, despite a decrease in kWh sales for the same period, primarily due to an increase in base rates in accordance with PEF's 2005 base rate settlement agreement, as previously discussed.

The economic conditions and general housing downturn in the United States has continued to contribute to a slowdown in customer growth and usage in PEF's service territory resulting in a 1.3 percent decrease in retail kWh sales for 2009, compared to 2008, and a 2.1 percent decrease for 2008, compared to 2007. The impact of the general housing downturn was especially severe in several states, including Florida. Additionally, we believe the current economic conditions have impacted our wholesale customers' usage. We cannot predict how long these economic conditions may last or the extent to which revenues may be impacted. In the future, PEF's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

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 $2.754 billion in 2009, which represents a $126 million increase compared to 2008. Fuel used in electric generation increased $397 million to $2.072 billion compared to 2008. This increase was primarily due to higher deferred fuel expense of $467 million driven by the implementation of new fuel rates, partially offset by decreased current year fuel costs of $70 million. The decrease in current year fuel costs was primarily due to lower system requirements. Purchased power expense decreased $271 million compared to the same period in 2008, primarily due to $164 million lower interchange costs and a decrease in the recovery of ~~deferred capacity costs of $91 million, both resulting from lower system requirements. See "PEF – Fuel and~~ Purchased Power" in Item 1, "Business," for a summary of average fuel costs.

Fuel and purchased power expenses were $2.628 billion in 2008, which represents an $18 million decrease compared to 2007. Fuel used in electric generation decreased $89 million to $1.675 billion primarily due to a $381 million decrease in deferred fuel expense, partially offset by increased fuel costs of $293 million. The decrease in 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. With the increase in fuel prices experienced in 2008, PEF successfully sought a mid-course fuel correction, but the revised fuel factors were not effective until August 2008. The increase in fuel costs was primarily due to increased fuel prices and a change in generation mix. Purchased power expense increased $71 million to $953 million compared to 2007. This increase was primarily due to increased purchases of $37 million as a result of higher fuel costs and an increase in the recovery of deferred capacity costs of $34 million.

Operation and Maintenance

O&M expense was $839 million in 2009, which represents a $26 million increase compared to 2008. The increase was primarily due to $63 million higher ECRC and energy conservation cost recovery clause (ECCR) costs primarily due to an increase in current year rates for recovery of emission allowances, higher pension costs of $24 million and higher nuclear plant outage and maintenance costs of $14 million, partially offset by lower storm cost recovery of $66 million due to the surcharge that ended in July 2008 and the impact of a change in our earned vacation policy of $11 million. The ECRC and ECCR expenses and replenishment of storm damage reserve are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Pension costs are higher due to a $20 million pension credit in the prior year. Substantially all of 2009's pension expense has been deferred in accordance with an FPSC order (See Note 7C). In the aggregate, O&M expenses recoverable through base rates increased $25 million compared to the same period in 2008.

O&M expense was $813 million in 2008, which represents a $21 million decrease compared to 2007. The decrease was primarily due to $24 million lower ECRC costs due to a decrease in the rates resulting from over-recovery, $12 million lower employee benefit costs primarily due to the 2007 impact from changes in stock-based compensation plans and $12 million lower sales and use tax audit adjustment, partially offset by $19 million related to storm damage reserves replenishment surcharge in effect August 2007 through July 2008 in accordance with a regulatory order, and $11 million higher plant outage and maintenance costs. The ECRC and replenishment of storm damage reserves expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates decreased $19 million compared to the same period in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $502 million for 2009, which represented an increase of $196 million compared to 2008, primarily due to higher nuclear cost-recovery amortization of $155 million (See Note

7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $31 million compared to 2008, primarily due to depreciable asset base increases.

Depreciation, amortization and accretion expense was $306 million for 2008, which represented a decrease of $60 million compared to 2007, primarily due to $75 million lower amortization of unrecovered storm restoration costs and a $7 million write-off in 2007 of leasehold improvements primarily related to vacated office space, partially offset by the $20 million impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a storm-recovery surcharge and, therefore, had no material impact on earnings (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $13 million compared to 2007, primarily due to depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $347 million, $309 million and $309 million in 2009, 2008 and 2007, respectively. The $38 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts and franchise taxes due to higher operating revenues. 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 expense was an expense of $7 million in 2009, income of $5 million in 2008 and an expense of $8 million in 2007. The $7 million expense in 2009 and the $8 million expense in 2007 were primarily due to regulatory disallowances of fuel costs (See Note 7C). The $5 million income in 2008 was primarily due to gain on land sales.

Total Other Income, Net

Total other income, net was $100 million for 2009, which represents a $6 million increase compared to 2008. This increase was primarily due to the $16 million of investment gains on certain employee benefit trusts resulting from improved market conditions, partially offset by $5 million lower interest income resulting from lower short-term investment balances and $4 million unfavorable AFUDC equity related to eligible construction project costs, primarily due to placing the repowered Bartow Plant into service in 2009.

Total other income, net was $94 million for 2008, which represents a $46 million increase compared to 2007. This increase was primarily due to $54 million favorable AFUDC equity related to eligible construction project costs, partially offset by $11 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

Total Interest Charges, Net

Total interest charges, net was $231 million in 2009, which represents an increase of $23 million compared to 2008. The increase in interest charges was primarily due to higher interest as a result of higher average debt outstanding.

Total interest charges, net was $208 million in 2008, which represents an increase of $35 million compared to 2007. The increase in interest charges was primarily due to the $60 million impact of an increase in average long-term debt, partially offset by $16 million favorable AFUDC debt related to costs associated with eligible construction projects and $7 million interest benefit resulting from the resolution of tax matters in 2008.

Income Tax Expense

Income tax expense was $209 million, $181 million and $144 million in 2009, 2008 and 2007, respectively. The $28 million income tax expense increase in 2009 compared to 2008 was primarily due to the $40 million impact of higher pre-tax income compared to the prior year, partially offset by the $11 million impact of the favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT fund to the qualified NDT fund. The $37 million income tax expense increase in 2008 compared to 2007 was primarily due to the $40 million impact of higher pre-tax income compared to 2007, $6 million benefit related to the closure of certain federal tax years and positions in 2007, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's 2005 base rate settlement agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense.

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 reportable business segment. A discussion of the items excluded from Corporate and Other's Ongoing Earnings is included in the detailed discussion and analysis below. Management believes the excluded items are not representative of our fundamental core earnings. The following table reconciles Corporate and Other's Ongoing Earnings to GAAP net income attributable to controlling interests:

(in millions)	**2009**	Change	2008	Change	2007
Other interest expense	**$(253)**	$(30)	$(223)	$(18)	$(205)
Other income tax benefit	**87**	1	86	(19)	105
Other income (expense)	**12**	13	(1)	17	(18)
Ongoing Earnings	**(154)**	(16)	(138)	(20)	(118)
CVO mark-to-market	**19**	19	–	2	(2)
Valuation allowance and related net operating loss carry forward	–	3	(3)	(3)	–
Impairment[(a)]	**(2)**	(2)	–	–	–
Discontinued operations attributable to controlling interests, net of tax	(79)	(136)	57	246	(189)
Net loss attributable to controlling interests	**(216)**	(132)	(84)	225	(309)

[(a)] Calculated using assumed tax rate of 40 percent.

Other Interest Expense

Other interest expense was $253 million, $223 million and $205 million for 2009, 2008 and 2007, respectively. The $30 million increase for 2009 compared to 2008 was primarily due to higher average debt outstanding at the Parent. The $18 million increase for 2008 compared to 2007 was primarily due to a $6 million 2007 benefit related to the closure of certain federal tax years and positions and a decrease in the interest allocated to discontinued operations. The decrease in interest allocated to discontinued operations resulted from the allocations of interest expense in early 2007 to operations that were sold later in 2007. An immaterial amount and $13 million of interest expense were allocated to discontinued operations for 2008 and 2007, respectively. No interest expense was allocated to discontinued operations in 2009.

Other Income Tax Benefit

Other income tax benefit was $87 million, $86 million and $105 million for 2009, 2008 and 2007, respectively. The $1 million increase for 2009 compared to 2008 was primarily due to higher pre-tax expenses, partially offset by the unfavorable impact at the Corporate level resulting from the deductions taken by the Utilities related to NDT funds (See "Progress Energy Carolinas – Income Tax Expense" and "Progress Energy Florida – Income Tax Expense"). The $19 million decrease for 2008 compared to 2007 was primarily due to the 2007 benefit related to the closure of certain federal tax years and positions.

Other Income (Expense)

Other income (expense) was $12 million income, $1 million expense and $18 million expense for 2009, 2008 and 2007, respectively. The $13 million change for 2009 compared to 2008 was primarily due to investment gains on certain employee benefit trusts resulting from improved financial market conditions. The $17 million change for 2008 compared to 2007 was primarily due to $15 million decreased indirect corporate overhead due to divestitures completed in 2007 and $12 million decreased legal expenses, partially offset by $8 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

CVO Mark-to-Market

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 (See Note 15). The CVOs had a fair value of $15 million at December 31, 2009, and $34 million at December 31, 2008 and 2007. Progress Energy recorded unrealized gains of $19 million for 2009 and unrealized losses of $2 million for 2007, to record the changes in fair value of the CVOs, which had average unit prices of $0.16 at December 31, 2009 and $0.35 at December 31, 2008 and 2007.

Valuation Allowance and Related Net Operating Loss Carry Forward

We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures, Inc.'s (PVI) nonregulated generation facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate.

Impairment

In 2009, Progress Energy recorded impairments of certain investments of our Affordable Housing portfolio.

Discontinued Operations Attributable to Controlling Interests, Net of Tax

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. See Note 3 for additional information related to discontinued operations.

In 2009, we recognized $79 million of expense from discontinued operations attributable to controlling interests, net of tax, which was primarily due to a jury delivering a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates previously engaged in coal-based solid synthetic fuels operations. As a result, we recorded an after-tax charge of $74 million to discontinued operations in 2009, which was net of a previously recorded indemnification liability. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information.

During 2008 we recognized $57 million of income from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $49 million after-tax gains on sales of our coal terminals and docks in West Virginia and Kentucky (Terminals) and our remaining coal mining businesses.

In 2007, we recognized $189 million of expense from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $283 million net losses related to the exit of the Competitive Commercial Operations (CCO) business, partially offset by $83 million net earnings related to the Terminals and Synthetic Fuels businesses. The net losses from the CCO business were primarily due to the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to de-designated natural gas hedges. We had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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.

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 accounting policies and 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 and estimates with the Audit and Corporate Performance Committee (Audit Committee) of our board of directors.

IMPACT OF UTILITY REGULATION

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. The application of GAAP for regulated operations to 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 regulatory 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.

Our conclusion that we and the Utilities meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our and the Utilities' financial position and results of operations. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by actions of our regulators, competitive forces and restructuring in the electric utility industry. State regulators may not allow the Utilities to increase future retail rates required to recover their operating costs or provide an adequate return on investment, or in the manner requested. State regulators may also seek to reduce or freeze retail rates. Such events occurring over a sustained period could result in the Utilities no longer meeting the criteria for the continued application of GAAP for regulated operations. In the event that GAAP for regulated operations no longer applies to one or both of the Utilities, we are subject to the risk that regulatory assets and liabilities would be eliminated and utility plant assets may be impaired, unless an appropriate recovery mechanism was provided. Additionally, our financial condition, cash flows and results of operations may be adversely impacted. See Note 7 for additional information related to the impact of utility regulation on our operations.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. 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. 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. The carrying values of our total utility plant, net at December 31 were as follows:

(in millions)	**2009**	2008
Progress Energy	**$19,733**	$18,293
PEC	**9,886**	9,385
PEF	**9,733**	8,790

As discussed in Note 13, our financial assets and liabilities are primarily comprised of derivative financial instruments and marketable debt and equity securities held in our nuclear decommissioning trusts. Substantially all unrealized gains and losses on derivatives and all unrealized gains and losses on nuclear decommissioning trust investments are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Therefore, the impact of fair value measurements from recurring financial assets and liabilities on our or the Utilities' earnings is not significant.

ASSET RETIREMENT OBLIGATIONS

Asset Retirement Obligations (AROs) represent legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability.

AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities.

Progress Energy's, PEC's and PEF's total AROs at December 31, 2009, were $1.170 billion, $801 million, and $369 million, respectively. We calculated the present value of our AROs based on estimates which are dependent on subjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 95 percent, 97 percent, and 91 percent, respectively, of Progress Energy's, PEC's and PEF's total AROs at December 31, 2009. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies 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. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized

PEC obtained updated cost studies for its nuclear plants in 2009, using 2009 cost factors. If the site-specific cost estimates increased by 10 percent, PEC's AROs would have increased by $77 million. If the inflation adjustment increased 25 basis points, PEC's AROs would have increased by $169 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEC's AROs by $56 million.

PEF obtained an updated cost study for its nuclear plant in 2008, using 2008 cost factors. If the site-specific cost estimates increased by 10 percent, PEF's AROs would have increased by $32 million. If the inflation adjustment increased 25 basis points, PEF's AROs would have increased by $25 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEF's AROs by $23 million.

GOODWILL

As discussed in Note 8, goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. The carrying amounts of goodwill at December 31, 2009 and 2008, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. We perform our annual impairment tests as of April 1 each year. During the second quarter of 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired. If the fair value of PEC had been lower by 10 percent and the fair value of PEF had been lower by 7.5 percent, there still would be no impact on the reported value of their goodwill

We calculate the fair value of our utility segments by considering various factors, including valuation studies based primarily on income and market approaches. More emphasis is applied to the income approach as substantially all of the utility segments' cash flows are from rate-regulated operations. In such environments, revenue requirements are adjusted periodically by regulators based on factors including levels of costs, sales volumes and costs of capital. Accordingly, the utility segments operate to some degree with a buffer from the direct effects, positive or negative, of significant swings in market or economic conditions

The income approach uses discounted cash flow analyses to determine the fair value of the utility segments. The estimated future cash flows from operations are based on the utility segments' business plans, which reflect management's assumptions related to customer usage based on internal data and economic data obtained from third-party sources. The business plans assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also determines the appropriate discount rate for the utility segments based on the weighted average cost of capital for each utility, which takes into account both the cost of equity and pre-tax cost of debt. As each utility segment has a different risk profile based on the nature of its operations, the discount rate for each reporting unit may differ.

The market approach uses implied market multiples derived from comparable peer utilities and market transactions to estimate the fair value of the utility segments. Peer utilities are evaluated based on percentage of revenues generated by regulated utility operations; percentage of revenues generated by electric operations; generation mix, including coal, gas, nuclear and other resources; market capitalization as of the valuation date; and geographic location. Comparable market transactions are evaluated based on the availability of financial transaction data and the nature and geographic location of the businesses or assets acquired, including whether the target company had a significant electric component. The selection of comparable peer utilities and market transactions, as well as the appropriate multiples from within a reasonable range, is a matter of professional judgment.

The calculations in both the income and market approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility segments could be significantly different in future periods, which could result in a future impairment charge to goodwill.

As an overall test of the reasonableness of the estimated fair values of the utility segments, we compared their combined fair value estimate to Progress Energy's market capitalization as of April 1, 2009. The analysis confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

We monitor for events or circumstances, including financial market conditions and economic factors, that may indicate an interim goodwill impairment test is necessary. We would perform an interim impairment test should any events occur or circumstances change that would more likely than not reduce the fair value of a utility segment below its carrying value.

UNBILLED REVENUE

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses.

Amounts recorded as receivables on the Balance Sheets at December 31 related to unbilled revenues were as follows:

(in millions)	2009	2008
Progress Energy	**$193**	$182
PEC	**125**	120
PEF	**68**	62

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 14, deferred income tax assets and liabilities represent the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax-planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. In accordance with GAAP, the uncertainty and judgment involved in the determination and filing of income taxes is accounted for 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: 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.

PENSION COSTS

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

Due to a slight decrease in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate to calculate the present value of future benefit payments, we decreased the discount rate to 6.00% at December 31, 2009, from 6.30% at December 31, 2008, which will increase 2010 pension costs, 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. Consistent with general market conditions, our plan assets performed well in 2009 with returns of approximately 23%. That positive asset performance will result in decreased pension costs in 2010, all other factors remaining constant. In addition, contributions to pension plan assets in late 2009 and 2010 will result in decreased pension costs in 2010 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2010 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2010 will be $80 million to $90 million, compared with $107 million (before the $34 million deferral; see Notes 7C and 16A) recognized in 2009.

We have pension plan assets with a fair value of approximately $1.7 billion at December 31, 2009. Our expected rate of return on pension plan assets is 8.75%. 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 2009, we lowered the expected rate of return from the previously used 9.00%, due primarily to the uncertainties resulting from the severe capital market deterioration in 2008. A 25 basis point change in the expected rate of return for 2009 would have changed 2009 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 8.75% expected long-term rate of return is applied. 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.

Since PEC and PEF participate in our pension plans, the general discussion above applies to PEC and PEF. PEC and PEF have not completed evaluating their 2010 pension costs. PEC estimates that the total cost recognized for pensions in 2010 will be $25 million to $30 million, compared with $32 million recognized in 2009. A 25 basis point change in the expected rate of return for 2009 would have changed PEC's 2009 pension costs by approximately $2 million. PEF estimates that the total cost recognized for pensions in 2010 will be $40 million to $45 million, compared with $57 million (before $34 million deferral; see Note 16A) recognized in 2009. A 25 basis point change in the expected rate of return for 2009 would have changed PEF's 2009 pension costs by approximately $2 million.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Our 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. As discussed in "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized.

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.

As a registered holding company, our establishment of intercompany extensions of credit is subject to regulation by the Federal Energy Regulatory Commission (FERC). Our subsidiaries participate in internal money pools, administered by PESC, to more effectively utilize cash resources and reduce external short-term borrowings. The utility money pool allows the 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.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.3 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries, repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures. During 2009, PEC paid a dividend of $200 million to the Parent and PEF received equity contributions of $620 million from the Parent. PEC and PEF expect to pay dividends to the Parent in 2010. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, and/or limited ongoing sales of common stock from our Progress Energy Investor Plus Plan (IPP), employee benefit and stock option plans are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2010. For the fiscal year 2010, we plan, subject to market conditions, to realize up to $500 million from the sale of stock through ongoing equity sales. As discussed further in "Credit Rating Matters," and in Item 1A, "Risk Factors," our ability to access the capital markets on favorable terms may be negatively impacted by recent, and potentially future, rating actions.

We have 16 financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as back-ups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009, the Parent had no outstanding borrowings under its credit facility, an outstanding commercial paper balance of $140 million and had issued $37 million of letters of credit, which were supported by the revolving credit facility. At December 31, 2009, PEC and PEF had no outstanding commercial paper. Based on these outstanding amounts at December 31, 2009, there was

$1.853 billion available for additional borrowings. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

Borrowings under our revolving credit agreement (RCA) during 2008, which were repaid during 2009, coupled with commercial paper, long-term debt and equity issuances in 2009, provided liquidity during a period of uncertain financial market conditions. We will continue to monitor the credit markets to maintain an appropriate level of liquidity.

At December 31, 2009, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2009, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for each of the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the sum of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps was each in a net mark-to-market asset position. See Note 17B for additional information with regard to our interest rate derivatives.

Our pension trust funds and nuclear decommissioning trust funds are managed by a number of financial institutions, and the assets being managed are diversified in order to limit concentration risk in any one institution or business sector.

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 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. Net cash provided by operating activities for the three years ended December 31, 2009, 2008 and 2007, was $2.271 billion, $1.218 billion and $1.252 billion, respectively.

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.053 billion increase in operating cash flow was primarily due to a $623 million increase in the recovery of deferred fuel costs due to higher fuel rates and $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $200 million net refunds of cash collateral in 2009. These impacts were partially offset by $221 million of pension and other benefits contributions made in 2009.

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $34 million decrease in operating cash flow was primarily due to a $450 million decrease in the recovery of fuel costs due to the 2008 under-recovery driven by rising fuel costs, compared to an over-recovery of fuel costs during the corresponding period in 2007; $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $55 million in net refunds of cash collateral in 2007, primarily at PEF; and a $226 million increase in inventory purchases, primarily coal, driven by higher prices. These impacts were partially offset by a $419 million increase from accounts receivable, primarily related to our divested CCO operations and former synthetic fuels businesses; the $347 million payment made in 2007 to exit the contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO (the Georgia contracts) (See Note 3C); a $117 million increase from accounts payable; and a $106 million increase from income taxes, net. The increase from accounts receivable was primarily driven by the settlement of $234 million of derivative receivables related to derivative contracts for our former synthetic fuels businesses (See Note 17A). The increase from income taxes, net was largely due to $252 million in income tax payments made in 2007 related to the sale of natural gas drilling and production business, partially offset by income tax impacts at PEC. The change in accounts payable was primarily related to our divested operations.

In 2009, 2008 and 2007, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2009, 2008 and 2007, was $2.532 billion, $2.541 billion and $1.457 billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.488 billion and $2.534 billion in 2009 and 2008, respectively, or approximately 100 percent of consolidated capital expenditures in both 2009 and 2008. 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 $1 million in 2009 and $72 million in 2008, cash used in investing activities decreased by $80 million. The decrease in 2009 was primarily due to a $24 million decrease in gross property additions at the Utilities, primarily due to lower spending for environmental compliance projects and the completion of PEF's Bartow Plant repowering project in 2009; a $22 million decrease in nuclear fuel additions; and a $20 million decrease in net purchases of 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.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $72 million in 2008 and $675 million in 2007, cash used in investing activities increased by $481 million. The increase in 2008 was primarily due to a $341 million increase in gross property additions at the Utilities, primarily at PEF, and a $95 million decrease in net purchases of available-for-sale securities and other investments. The increase in capital expenditures for utility property additions at PEF was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility.

During 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds of $63 million from the sale of Terminals and Coal Mining (See Notes 3A and 3B).

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 3C), working capital adjustments related to the sale of natural gas drilling and production business, and the sale of poles at Progress Telecommunications Corporation.

FINANCING ACTIVITIES

Net cash provided by financing activities for the three years ended December 31, 2009, 2008 and 2007, was $806 million, $1.248 billion and $195 million, respectively. See Note 11 for details of debt and credit facilities.

The decrease in net cash provided by financing activities for 2009 compared to 2008 is primarily due to a $2.077 billion net decrease in short-term indebtedness, primarily driven by commercial paper repayments and the Parent's repayment of borrowings outstanding under its RCA; partially offset by a $491 million increase in proceeds from the issuance of common stock, primarily related to the Parent's January 2009 common stock offering; a $481 million increase in net proceeds from long-term debt issuances due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $1.500 billion issuance and PEC's $325 million issuance in 2008; a $477 million decrease in payments at maturity of long-term debt; and a $118 million decrease in net payments on short-term debt with original maturities greater than 90 days.

The increase in net cash provided by financing activities for 2008 compared to 2007 is primarily due to PEF's $1.475 billion net proceeds and PEC's $322 million net proceeds from the issuance of long-term debt in 2008 discussed below, compared to $739 million in net proceeds in 2007. Additionally, net short-term debt increased in 2008 compared to 2007 due to $600 million in outstanding borrowings under the Parent's RCA, and outstanding commercial paper issuances of $69 million at the Parent, $110 million at PEC and $371 million at PEF, compared to outstanding commercial paper issuances of $201 million at the Parent in 2007. The increase in proceeds from long-term debt issuances was offset by $877 million in long-term debt retirements in 2008, $176 million in payments on short-term debt; and $85 million in cash distributions to owners of minority interests of consolidated subsidiaries primarily related to the settlement of Ceredo Synfuel LLC's (Ceredo) synthetic fuels derivatives contracts (See Note 17A).

Our financing activities are described below.

2010

- On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

- Subsequent to December 31, 2009, the Parent has issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million. On February 3, 2009, the Parent used $100 million of the proceeds to reduce its $600 million RCA balance outstanding at December 31, 2008, and the remainder was used for general corporate purposes.

- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.

- On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

- On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

- On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to pre-fund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

- During 2009, we repaid the November 2008 $600 million borrowing under our RCA.

- Progress Energy issued approximately 3.1 million shares of common stock resulting in approximately $100 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.5 million shares for proceeds of approximately $100 million issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the IPP. For 2009, the dividends paid on common stock were approximately $693 million.

2008

- 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 RCAs 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 (See "Credit Facilities and Registration Statements").

- 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 6.65% 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, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire ~~on May 3, 2012 (See "Credit Facilities and Registration Statements").~~

- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.

- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. The borrowing was repaid during 2009.

- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the 401(k) and the IPP. For 2008, the dividends paid on common stock were approximately $642 million.

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 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.

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $151 million in proceeds from its IPP and its equity incentive plans. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million issued for the IPP. For 2007, the dividends paid on common stock were approximately $627 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, 2009, 2008 and 2007. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has 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 December 31, 2009, we have carried forward $712 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.

We expect to be able to meet our future liquidity needs through cash from operations, commercial paper issuance, availability under our credit facilities, long-term debt financings and equity offerings. We may also use periodic ongoing sales of common stock from our IPP and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. As a result of financial and economic conditions in 2008 and 2009, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. The Parent borrowed $600 million under its RCA in November 2008 and repaid the outstanding balance during 2009 with proceeds from the January 2009 equity issuance, cash on hand and proceeds from commercial paper borrowings. If liquidity conditions deteriorate again 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 under our RCA, issuing short-term notes, issuing long-term debt and/or issuing equity. If our short-term credit ratings are downgraded below Tier 2 (A-2/P-2/F2), we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets could be negatively impacted. In the event of a downgrade of our senior unsecured credit ratings, our credit facility fees and borrowing rates under our RCA's could increase. We do not expect an increase in such RCA fees to be material. See "Credit Rating Matters" for further discussion regarding credit ratings.

The current RCAs for the Parent, PEC and PEF expire in May 2012, June 2011 and March 2011, respectively. We are currently evaluating options for addressing these upcoming expirations. In the event we enter into new credit facilities, we cannot predict the terms, prices, durations or participants in such facilities.

Progress Energy and its subsidiaries have approximately $12.051 billion in outstanding long-term debt. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may move our tax-exempt bonds below A3/A-. PEC's senior secured debt ratings are currently A1 by Moody's Investors Service, Inc. (Moody's) and A-/Watch Negative by Standard and Poor's Rating Services (S&P). PEF's senior secured debt ratings are currently A1/Watch Negative by Moody's and A-/Watch Negative by S&P. In the event of a one notch downgrade of PEC's and/or

PEF's senior secured debt rating by S&P, the ratings of both utilities' tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a one notch downgrade by Moody's, PEC's and PEF's tax-exempt bonds will continue to be rated above A3. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $120 million of contributions directly to pension plan assets in 2010 (See Note 16).

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," 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/or 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. As discussed in "Other Matters – Nuclear – Potential New Construction," PEF expects its capital expenditures for the Levy project will be significantly less in the near term than previously planned in light of a regulatory schedule shift and other factors.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. At February 19, 2010, we had posted approximately $168 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2010 and 2011. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. In addition, as discussed in "Credit Rating Matters," if our credit ratings are downgraded, we may have to post additional cash collateral for derivatives in a liability position.

The amount and timing of future sales of debt and equity securities will depend on market conditions, operating cash flow 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, 2009, the current portion of our long-term debt was $406 million. On January 15, 2010, we funded the $100 million Series A Floating Rate Notes maturity with proceeds from the Parent's November 2009 $950 million long-term debt issuance, and we expect to fund the remaining $306 million with a combination of cash from operations, commercial paper borrowings and long-term debt.

See "Credit Rating Matters" for information regarding recent rating actions.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 7 and "Other Matters – Regulatory Environment," 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. Regulatory developments expected to have a material impact on our liquidity are discussed below.

As discussed further in Note 7 and in "Other Matters – Regulatory Environment," the North Carolina, South Carolina and Florida legislatures passed energy legislation that became law in recent years. These laws may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and energy efficiency.

PEC Cost-Recovery Clause

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On June 19, 2009, the SCPSC approved a settlement agreement filed jointly by PEC and the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million, which went into effect July 1, 2009.

On June 4, 2009, PEC filed with the North Carolina Utilities Commission (NCUC) for a decrease in the fuel rate charged to its North Carolina ratepayers. The filing was updated on August 17, 2009. PEC asked the NCUC to approve a $14 million decrease in the fuel rates driven by declining fuel prices, which went into effect December 1, 2009. At December 31, 2009, PEC's North Carolina deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010.

PEC Other Matters

On October 13, 2008, the NCUC issued a Certificate of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 600-MW combined cycle dual fuel capable generating facility at its Richmond County generation site to provide additional generating and transmission capacity to meet the growing energy demands of southern and eastern North Carolina. PEC expects that the new generating and transmission capacity will be online by the second quarter of 2011.

As discussed in Note 7 and in "Other Matters – Environmental Matters," on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. We intend to continue to depreciate the three coal-fired units at their current depreciation rate until PEC's next depreciation study. PEC projects that the generating facility would be in service by January 2013. The filed estimate of capital expenditures, net of AFUDC – borrowed funds for the new generating facility is approximately $800 million. PEC modified its Clean Smokestacks Act compliance plan for the change in fuel source and removed retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC, which decreased estimated capital expenditures to meet the Clean Smokestacks Act emission targets by 2013 to $1.1 billion from $1.4 billion. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

In accordance with the October 2009 NCUC order, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. We intend to continue to depreciate the coal-fired units at their current depreciation rate until PEC's next depreciation study. On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. The filed estimate of capital expenditures, net of AFUDC – borrowed funds for the new generating facility is approximately $600 million. PEC projects that the generating facility would be in service by late 2013 or early 2014.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for

PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. The interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual O&M costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options.

PEF Cost-Recovery Clauses

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced customers' fuel charges starting with the first billing cycle of April 2009.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. On October 23, 2009, PEF filed a $3 million cost adjustment with the FPSC, which reduced the capacity cost-recovery clause (CCRC) rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

In addition, on August 28, 2009 and as updated on October 27, 2009, PEF filed a request to increase the ECRC residential rate. Also, on September 14, 2009, PEF filed a request to increase the ECCR residential rate. The FPSC approved a combined $37 million increase in PEF's ECRC and ECCR clauses on November 2, 2009, to be effective January 1, 2010.

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. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve its integrated strategy to address compliance with 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 the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the CCRC. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after 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. 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. On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs through the CCRC, and found that PEF's project management, contracting, and oversight controls were reasonable and prudent. As discussed in Note 7, on October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced customers' nuclear cost-recovery charge starting with the first billing cycle of April 2009.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million through the nuclear cost-recovery clause of the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt and equity 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 2009.

As shown in the table that follows, 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. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2009**	2010	2011	2012
Regulated capital expenditures	**$1,995**	$2,160	$2,120	$1,810
Nuclear fuel expenditures	**200**	230	300	260
AFUDC-borrowed funds	**(37)**	(30)	(40)	(40)
Other capital expenditures	**7**	30	30	30
Total before potential nuclear construction	**2,165**	2,390	2,410	2,060
Potential nuclear construction[a]	**291**	100 – 150	60 – 70	60 –70
Total	**$2,456**	$2,490 – 2,540	$2,470 – 2,480	$2,120 – 2,130

[a] Expenditures for potential nuclear construction are net of AFUDC – borrowed funds.

Regulated capital expenditures for 2010, 2011 and 2012 in the previous table include approximately $130 million, $40 million and $100 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2010, 2011 and 2012 include $20 million, $40 million and $50 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2010 and 2012 include $110 million and $50 million, respectively, at PEF. No environmental compliance capital expenditures are forecasted for PEF in 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

Potential nuclear construction expenditures, which are primarily for PEF's Levy, include development, licensing and equipment. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. (See discussion under "Other Matters – Nuclear – Potential New Construction") The forecasted capital expenditures presented in the previous table reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and/or exit costs cannot be determined at this time and, accordingly, are not included in the previous table. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

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

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities

The following tables summarize our RCAs and available capacity at December 31:

2009 **(in millions)**	**Description**	**Total**	**Outstanding[a]**	**Reserved[b]**	**Available**
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$ –**	**$177**	**$1,853**

2008 (in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
Parent	Five-year (expiring 5/3/12)	$1,130	$ 600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$ 600	$580	$850

(a) The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had a total amount of $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

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 11 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 the Parent's RCA are based upon the credit rating of the Parent's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2/Watch Negative by Moody's and BBB/Watch Negative 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+/Watch Negative 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/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

All of the credit facilities include defined maximum total debt-to-total capital ratio (leverage) covenants, which we were in compliance with at December 31, 2009. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2009, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 11.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited 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.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount 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 based on property additions, retirements of First Mortgage Bonds and the deposit of cash, provided that adjusted net earnings are at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2009, PEC and PEF could issue up to approximately $6.0 billion and $2.6 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. At December 31, 2009, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 4.9 times and 3.4 times, respectively.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

	2009	2008
Total equity	**42.3%**	41.9%
Preferred stock	**0.4%**	0.5%
Total debt	**57.3%**	57.6%

CREDIT RATING MATTERS

At February 22, 2010, the major credit rating agencies rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Long-Term Ratings			
Parent			
Outlook/Watch	Watch Negative[(a)]	Watch Negative[(b)]	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
PEC			
Outlook/Watch	Stable	Watch Negative[(b)]	Stable
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	BBB+
PEF			
Outlook/Watch	Watch Negative[(a)]	Watch Negative[(b)]	Watch Negative[(c)]
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Preferred stock	Baa2	BBB-	BBB+
Florida Progress Corporation (FPC) Capital I			
Outlook/Watch	Watch Negative[(a)]	Watch Negative[(b)]	Watch Negative[(c)]
Quarterly Income Preferred Securities[(d)]	Baa2	BBB-	BBB+
Short-Term Ratings			
Parent			
Watch	Watch Negative[(a)]	N/A	N/A
Commercial Paper	P-2	A-2	F2
PEC			
Watch	N/A	N/A	N/A
Commercial Paper	P-2	A-2	F1
PEF			
Watch	N/A	N/A	Watch Negative[(c)]
Commercial Paper	P-2	A-2	F1

(a) On January 19, 2010, Moody's placed these ratings on review for possible downgrade.
(b) On January 14, 2010, S&P placed these ratings on CreditWatch Negative.
(c) On January 12, 2010, Fitch placed these ratings on Rating Watch Negative.
(d) Guaranteed by the Parent and FPC.

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 August 3, 2009, Moody's raised the senior secured debt rating of both PEC and PEF to A1 from A2 as a result of Moody's reevaluating its notching criteria for investment-grade regulated utilities to reflect the historical lower default rates for regulated utilities than for non-financial, non-utility corporate issuers.

On January 12, 2010, Fitch placed ratings of PEF and FPC Capital I on Rating Watch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Fitch cited lower cash flow expectations and increased regulatory risk as drivers for the rating action.

On January 14, 2010, S&P placed ratings of Progress Energy, Inc. and its subsidiaries, including PEC, PEF, FPC Capital I and Florida Progress Corp., on CreditWatch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. At the same time, S&P affirmed the 'A-2' short-term ratings on Progress Energy, Inc., PEC and PEF.

On January 19, 2010, Moody's placed the long-term ratings of Progress Energy, Inc. and PEF on review for possible downgrade as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Moody's also placed the short-term rating for commercial paper of Progress Energy, Inc. on review for possible downgrade. At the same time, Moody's affirmed the ratings and stable outlook of PEC.

As noted above, the three rating agencies cited increased regulatory risk and PEF's rate case outcome as the key driver of the ratings actions. Credit rating changes could be made after the agencies have completed their reviews of PEF's rate order and our response to the decision.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customer's future energy needs (See Item 1A, "Risk Factors").

As discussed in Note 17C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

On January 22, 2010, Fitch lowered the rating on PEC's, PEF's and FPC Capital I's preferred securities to BBB+ from A- as a result of the implementation of Fitch's revised guidelines for rating preferred stock and hybrid securities.

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. 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, 2009, we have issued $406 million of guarantees for future financial or performance assurance, including $11 million at PEC. 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). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. 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, 2009, 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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented in the following table are estimates and therefore will likely differ from actual purchase amounts. 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, 2009, 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 11)	$12,515	$406	$1,950	$1,125	$9,034
Interest payments on long-term debt[b]	10,077	707	1,289	1,073	7,008
Capital lease obligations[c] (See Note 22B)	484	34	67	74	309
Operating leases[c] (See Note 22B)	1,430	35	83	181	1,131
Fuel and purchased power[d] (See Note 22A)	24,070	3,092	5,202	3,923	11,853
Other purchase obligations[e] (See Note 22A)	9,749	1,872	3,288	2,883	1,706
Minimum pension funding requirements[f]	794	74	353	229	138
Other postretirement benefits[g] (See Note 16A)	397	34	73	79	211
Uncertain tax positions[h] (See Note 14)	–	–	–	–	–
Other commitments[i]	105	13	26	26	40
Total	$59,621	$6,267	$12,331	$9,593	$31,430

(a) Our 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, 2009.

(c) Amounts include certain related executory cost commitments.

(d) Essentially all fuel and certain purchased power costs incurred by the Utilities are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

(e) Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. The contractual obligations presented are in accordance with the existing terms of the EPC agreement, which assumes the original construction schedule and 100 percent ownership by PEF. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction.") We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in this table.

(f) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(g) Represents projected benefit payments for a total of 10 years related to our postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

(h) Uncertain tax positions of $160 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements.

(i) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

REGULATORY ENVIRONMENT

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the 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 American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency and renewable energy, including $3.4 billion in Smart Grid technology development grants, $615 million for Smart Grid storage, monitoring and technology viability, $6.3 billion for energy-efficiency and conservation grants and $2 billion in tax credits for the purchase of plug-in electric vehicles. In August 2009, we submitted our application to the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our investment in Smart Grid-related technologies in the Carolinas and Florida. On October 27, 2009, the DOE notified us of our selection for Smart Grid award negotiations. We are now awaiting further questions and comments from the DOE on our Smart Grid application. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the incentive programs. Also, the Obama administration has announced a goal of encouraging investment in transmission and promoting renewable resources while also pricing GHG emissions and setting a federal requirement for renewable energy.

On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national renewable energy portfolio standard (REPS). The bill also calls for investment in the electric grid, more production and utilization of electric vehicles and improvements in energy efficiency in buildings and appliances. The full impact of the legislation, if enacted into law, cannot be determined at this time and will depend upon changes made to its provisions during the legislative process and the manner in which key provisions are implemented, including the regulation of carbon. The U.S. Senate is considering similar proposals. The full impact of final legislation, if enacted, and additional regulation resulting from these and other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery.

Current retail rate matters affected by state regulatory authorities are discussed 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 July 31, 2009, the governor of North Carolina signed into law a bill that includes three key provisions that may impact PEC. First, the legislation accelerates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal unit at that specific site. Pursuant to the legislation, PEC requested and received approval from the NCUC to pursue construction of a new 950-MW natural gas plant (see further discussion in Note 7B and "Other Matters – Environmental Matters"). Second, a recovery mechanism is provided for utilities if they invest in zero emissions renewable energy facilities within the next five years. Finally, the legislation changes the state's Dam Safety Act such that dams at utility coal-fired power plants, including dams for ash ponds, will be subject to the Act's applicable provisions, including state inspection, as of January 1, 2010.

Florida energy law enacted in 2008 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 GHG 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. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until these agency actions are finalized, we cannot predict the costs of complying with the law.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of GHGs 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. To date, the FDEP has held three rulemaking workshops on the GHG cap-and-trade rulemaking. Rulemaking is expected to continue through 2010, and the rule requires legislative ratification before implementation.

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 onsite 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). On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter.

We cannot predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

North Carolina energy law enacted in 2007 includes provisions for a North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), 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 2007 energy law. The rules include filing requirements regarding NC REPS compliance and inclusion in the Utility's integrated resource plan. 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 NC REPS clause will be set based on projected costs with true-up provisions. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results.

ENERGY DEMAND

Implementing state and federal energy policies, promoting environmental stewardship and providing reliable electricity to meet the anticipated long-term 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 DSM, energy-efficiency and conservation programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. We provide our residential customers with home energy audits and offer energy-efficiency programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet Web site with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative energy projects to pursue the generation of electricity from swine waste and other plant or animal sources, biomass, solar, hydrogen, and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 250 MW of electricity generated from biomass and up to 60 MW of electricity generated from municipal solid waste sources. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 10 MW of electricity generated from solar photovoltaic generation as part of the NC REPS. The majority of these projects are online and the remainder should be online by early 2010. Additionally, customers across our service territory have connected approximately 4 MW of solar photovoltaic energy systems to our grid. In June 2009, we expanded our solar energy strategy to include a range of new solar incentives and programs, which are expected to increase our use of solar energy by more than 100 MW over the next decade.

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.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The coal-fired units will be retired by the end of 2017. PEC has received approval from the NCUC for construction of a 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has requested approval from the NCUC to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C. The facility is projected to be placed in service in late 2013 or early 2014. PEC will continue to operate three coal-fired plants in North Carolina after 2017. PEC has invested more than $2 billion in installing state-of-the-art emission controls at the Roxboro, Mayo and Asheville Plants. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at those sites.

As authorized under the Energy Policy Act of 2005 (EPACT), on October 4, 2007, the 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. In June 2008, the DOE announced solicitations for a total of up to $30.5 billion of the amount authorized by Congress in federal loan guarantees for projects that employ advanced energy technologies that avoid, reduce or sequester air pollutants or greenhouse gas emissions and advanced nuclear facilities for the "front-end" of the nuclear fuel cycle.

PEF submitted Part I of the Application for Federal Loan Guarantees for Nuclear Power Facilities on September 29, 2008, for Levy. PEF was one of 19 applicants that submitted Part I of the application. The program requires that the guarantee be in a first lien position on all assets of the project, which conflicts with PEF's current mortgage. Obtaining the required approval to amend the current mortgage from 100 percent of PEF's current bondholders would be unlikely, and current secured debt of $4.0 billion would need to be refinanced with unsecured debt to meet the requirements of the guarantee. In addition, the costs associated with obtaining the loan guarantee are unclear. PEF decided not to pursue the loan guarantee program and did not submit Part II of the application, which was due on December 19, 2008. However, this decision does not preclude PEF from revisiting the program at a later date if there are changes to the program. We cannot predict if PEF will pursue this program further.

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 filed 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.

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. Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

CR3 is currently undergoing an extended outage for normal refueling and maintenance as well as a project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, finalized repair estimates and replacement power costs, or the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

The NRC operating licenses for PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, if approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida. The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on the potential construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

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 17, 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. No petitions to intervene have been admitted in the Harris COL application. 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 2019 (See "Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy 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. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. 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. On May 29, 2008, the Florida Department of Community Affairs issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

In 2008, PEF submitted filings for two key state approvals. First, on March 11, 2008, PEF filed a Petition for a Determination of Need for Levy with the FPSC. The FPSC issued a final order granting PEF's petition for Levy on August 12, 2008. Second, on June 2, 2008, PEF filed its application for site certification with the FDEP. Certification addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government. On January 12, 2009, the FDEP filed a favorable staff analysis report in advance of certification hearings. The technical proceedings concluded on March 12, 2009, and the administrative law judge issued a recommended order on certification on May 15, 2009. The Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy certification on August 26, 2009.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. On October 6, 2008, the NRC docketed, or accepted for review, the Levy 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. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On April 20-21, 2009, the Atomic Safety Licensing Board (ASLB) heard oral arguments on whether any of the joint interveners' proposed contentions will be admitted in the Levy COL proceeding. On July 8, 2009, the ASLB issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. We cannot predict the outcome of this matter.

PEF expects a schedule shift for the commercial operation dates of the Levy nuclear units. PEF's initial schedule anticipated the ability to perform certain site work pursuant to a Limited Work Authorization from the NRC prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the Limited Work Authorization scope will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

As discussed below, the schedule shift will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates. The schedule shift will also allow more time for certainty around federal climate change policy, which is currently being debated. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. We still consider Levy as

PEF's preferred baseload generation option, taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including public, regulatory and political support; adequate financial cost-recovery mechanisms; customer rate impacts, project feasibility and availability and terms of capital financing.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the ~~termination circumstances. We anticipate amending the EPC agreement due to the schedule shift previously~~ discussed but cannot predict the impact such amendment might have on the project's cost, if any.

Florida regulations allow investor-owned utilities such as PEF to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balance of a nuclear power plant prior to commercial operation. The costs are recovered on an annual basis through the CCRC. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after 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. 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.

In 2008, PEF sought and received approval from the FPSC to recover Levy preconstruction and carrying charges of $357 million as well as site selection costs of $38 million through the 2009 CCRC. In 2009, PEF received approval to defer until 2010 the recovery of $198 million of these costs (See Note 7C). On October 16, 2009, the FPSC approved the recovery of $201 million of preconstruction costs, carrying costs and incremental O&M incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with Levy as part of the total $207 million FPSC-approved recovery of nuclear costs through the 2010 CCRC (See Note 7C).

At December 31, 2009, PEF's unrecovered investment in Levy totaled $404 million, of which $358 million is recoverable in retail rates through the Florida nuclear cost-recovery rules, including $296 million of construction work in progress, of which $274 million was reflected as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs and $22 million was reflected as a deferred fuel regulatory asset. The remaining $46 million is apportioned to PEF's wholesale jurisdiction and would be recovered through PEF's wholesale rates. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and/or exit costs that would increase its unrecovered investment. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time.

PEC's jurisdictions also have laws encouraging nuclear baseload generation. South Carolina law includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. North Carolina law authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and inclusion of construction work in progress in rate base with corresponding rate adjustment in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

SPENT NUCLEAR FUEL MATTERS

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. We have a contract with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nev. The Obama administration has determined that Yucca Mountain, Nev., is not a workable option for a nuclear waste repository and will discontinue its program to construct a repository at this site in 2010. The administration will continue to explore alternatives. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or spent nuclear fuel reprocessing. We cannot predict the outcome of this matter.

The NRC has proposed revisions to its waste confidence findings that would remove the provisions stating that the NRC's confidence in waste management, underlying the licensing of reactors, is based in part on a permanent repository being in operation by 2025. Instead, the NRC states that repository capacity will be available within 50 to 60 years beyond the licensed operation of all reactors, and that used fuel generated in any reactor can be safely stored on site without significant environmental impact for at least 60 years beyond the licensed operation of the reactor. We cannot predict the outcome of this matter.

On September 15, 2009, the NRC proposed licensing requirements for storage of spent nuclear fuel, which would clarify the term limits for specific licenses for independent spent fuel storage installations and for certificates of compliance for spent nuclear fuel storage casks. The agency proposal would formalize the site-by-site exemption the NRC has used for renewal applications requesting more than the current 20-year duration. The initial and renewal terms of a specific installation license would be effective for a period of up to 40 years. Similarly, the proposed rule would allow applicants for certificates of compliance to request initial and renewal terms of up to 40 years, provided they can demonstrate that all design requirements are satisfied for the requested term. We cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation and/or expansion of on-site dry cask storage facilities at PEC's Robinson Nuclear Plant (Robinson), Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated by their respective systems through the expiration of the operating licenses, including any license renewals, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license.

See Note 22D for information about the complaint filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open the Yucca Mountain or other facility would leave the DOE open to further claims by utilities.

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.

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 liability. 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 potential and pending claims cannot be predicted. 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. 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.

As discussed in "Other Matters – Regulatory Environment," as of January 1, 2010, dams at utility fossil-fired power plants, including dams for ash ponds, are subject to the North Carolina Dam Safety Act's applicable provisions, including state inspection. Until the state agency responsible for dam safety inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. However, these dams have been subject to periodic third-party inspection in accordance with prior applicable requirements.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary.

In June 2009, the EPA evaluated information about ash impoundment dams nationwide and posted a listing of 44 utility ash impoundment dams that are considered to have "high hazard potential," including two of PEC's ash impoundment dams. A "high hazard potential" rating is not related to the stability of those ash ponds but to the potential for harm should the impoundment dam fail. As noted above, all of the dams at PEC's coal ash ponds have been subject to periodic third-party inspection. In September 2009, the EPA rated the 44 "high hazard potential" impoundments, as well as other impoundments, from "unsatisfactory" to "satisfactory" based on their structural integrity and associated documentation.

Only dams rated as "unsatisfactory" would be considered to pose an immediate safety threat, but none of the facilities received an "unsatisfactory" rating. In total, six of PEC's ash pond dams, including one "high hazard potential" impoundment, were rated as "poor" based on the contract inspector's desire to see additional documentation and their evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the recommendations for the active ponds and other recommendations are under way. We are working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

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 likely would result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require reductions in air emissions of NOx, sulfur dioxide (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 installed pursuant to the provisions of CAIR, CAVR and mercury regulations, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the

CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. On March 31, 2009, 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 \$1.4 billion at the time of the filing. As discussed in "Other Matters – Regulatory Environment," North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. The law gives PEC the option to seek certification, construct a new natural gas plant and retire existing coal units, with resulting reduced emissions, in time to comply with the Clean Smokestacks Act's 2013 emission targets. As discussed in Note 7B on October 22, 2009, the NCUC issued an order granting PEC a certificate of public convenience and necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. PEC projects that the generating facility would be in service by January 2013. On December 1, 2009, PEC filed with the NCUC a plan to retire, no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC modified its Clean Smokestacks Act compliance plan to remove retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC totaling \$1.1 billion of capital expenditures to meet the Clean Smokestacks Act emission targets. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expenses increase with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; all other O&M expenses are currently recoverable through base rates

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).

Clean Air Interstate Rule

The CAIR issued by the EPA on March 10, 2005, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set 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.

The air quality controls installed to comply with the requirements of the NOx State Implementation Plan Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, largely address the CAIR requirements for our North Carolina units at PEC. PEF met the 2009 phase I requirements for NOx and anticipates meeting the 2010 phase I requirements of CAIR for NOx and SO_2 with a combination of emission reductions generated by in-service emission control equipment and emission allowances. PEF's CR5 equipment was placed in service on December 2, 2009, and PEF's CR4 equipment is expected to be placed in service in 2010.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, the

D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The EPA informed the D.C. Court of Appeals that development and finalization of a replacement rule could take approximately two years. The outcome of this matter cannot be predicted.

Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and 2 coal-fired steam turbines (CR1 and CR2) and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. Accordingly, PEF has advised the FDEP of an expected shift in the Levy schedule as discussed in "Other Matters – Nuclear – Potential New Construction." We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

Clean Air Mercury Rule

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 (MACT) approach for limiting mercury emissions from coal-fired power plants. On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the CAMR. The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a MACT standard consistent with the agency's original listing determination. The three states in which the Utilities operate adopted mercury regulations implementing the CAMR and submitted their state implementation rules to the EPA. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

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, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. 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, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, on December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeals' December 23, 2008 decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for SO_2 and NOx. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, the FDEP has not determined the level of additional controls PEF may need to implement. The outcome of these matters cannot be predicted.

Compliance Strategy

Both PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with the requirements of the NOx SIP Call and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, resulted in a reduction of the costs to meet PEC's CAIR requirements.

PEC has completed installation of controls to meet the NOx SIP Call requirements. The NOx SIP Call is not applicable to sources in Florida. Expenditures for the NOx SIP Call included the cost to install NOx controls under programs by North Carolina and South Carolina to comply with the federal eight-hour ozone standard.

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (see discussion above regarding the vacating of the CAMR and remanding of the CAIR). PEF's April 1, 2009 filing with the FPSC for true-up of final 2008 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.2 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote and Crystal River Plants. As discussed in Note 7C, on August 28, 2009, PEF filed for recovery of costs through the ECRC, and the FPSC approved PEF's filing on November 2, 2009. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations, changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. The timing and extent of the costs for future projects will depend upon final compliance strategies.

The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the tables exclude AFUDC.

Progress Energy

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act[a]	2002 – 2013	$1,100	$1,050
In-process CAIR projects[b]	2005 – 2010	1,200	1,065
CAVR[c]	– 2017	–	–
Mercury regulation[d]	2006 – 2017	–	4
Total air quality		2,300	2,119
Clean Water Act Section 316(b)[e]		–	–
Total air and water quality		$2,300	$2,119

PEC

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act[a]	2002 – 2013	$1,100	$1,050
In-process CAIR projects[b]	2005 – 2008	–	–
CAVR[c]	– 2017	–	–
Mercury regulation[d]	2006 – 2017	–	4
Total air quality		1,100	1,054
Clean Water Act Section 316(b)[e]		–	–
Total air and water quality		$1,100	$1,054

PEF

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
In-process CAIR projects[b]	2005 – 2010	$1,200	$1,065
CAVR[c]	– 2017	–	–
Mercury regulation[d]		–	–
Total air quality		1,200	1,065
Clean Water Act Section 316(b)[e]		–	–
Total air and water quality		$1,200	$1,065

(a) PEC is continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

(b) PEF is continuing construction of its in-process emission control projects. Additional compliance plans for PEC and PEF to meet the requirements of a revised rule will be determined upon finalization of the rule. See discussion under "Clean Air Interstate Rule."

(c) As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed. See discussion under "Clean Air Visibility Rule."

(d) Compliance plans to meet the requirements of a revised or new implementing rule will be determined upon finalization of the rule. See discussion under "Clean Air Mercury Rule."

(e) 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."

All environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, which included projects at PEC's Asheville, Lee, Mayo and Roxboro Plants, have been placed in service. On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. Additional projects requiring material environmental compliance costs may be implemented in the future to meet compliance requirements.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. As a result of changes in the scope of work related to estimation of costs for compliance with the CAIR and the uncertainty regarding the EPA's further CAIR proceedings, the delisting determination and the CAMR discussed above, PEF is currently unable to estimate certain costs of compliance. However, PEF believes that future costs to comply with new or subsequent rule interpretations could be significant. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when those new regulations are finalized.

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 fossil fuel-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 Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In 2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial. In 2009, the D.C. Court of Appeals remanded the EPA's denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

In 2006, the EPA announced changes to the NAAQS for particulate matter. The changes in particulate matter standards did not result in designation of any additional nonattainment areas in PEC's or PEF's service territories. Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. The outcome of this matter cannot be predicted.

In 2008, the EPA revised the 8-hour primary and secondary standards for the NAAQS for ground-level ozone. Additional nonattainment areas may be designated in PEC's and PEF's service territories as a result of these revised standards. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The EPA requested the D.C. Court of Appeals to suspend proceedings in the case while the EPA evaluates whether to maintain, modify or otherwise reconsider the revised NAAQS. In September 2009, the EPA announced that it is reconsidering the level of the ozone NAAQS. The EPA originally indicated plans to designate nonattainment areas for these standards by March 2010. However, the EPA announced that it will stay those designations until after its reconsideration has been completed.

On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. The EPA plans to finalize the revisions by August 31, 2010, and to designate nonattainment areas by August 2011. The proposed revisions are significantly more stringent than the current NAAQS. 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.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide. Since 1971, when the first NAAQS were promulgated, the standard for nitrogen dioxide has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. The EPA plans to designate nonattainment areas by January 2012. Currently, there are no monitors reporting violation of the new standard in PEC's or PEF's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas. The outcome of this matter cannot be predicted.

On December 8, 2009, the EPA proposed a new 1-hour NAAQS for sulfur dioxide. The current primary NAAQS on a 24-hour average basis and annual average would be eliminated under the proposed rule. A 1-hour standard in the proposed range is a significant increase in the stringency of the standard and it would increase the risk of nonattainment, especially near uncontrolled coal-fired facilities. 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.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants to determine whether changes at those facilities were subject to New Source Review 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 included reported expenditures in excess of $1.0 billion for retrofit of pollution control equipment. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the unaffiliated utilities may seek recovery of the related costs through rate adjustments or similar mechanisms.

Water Quality

1. General

As a result of the operation of certain pollution control equipment required to comply with the air quality issues outlined above, new sources of wastewater discharge will be generated at certain affected facilities. Integration of these new wastewater discharges into the existing wastewater treatment processes is currently ongoing and will result in permitting, construction and treatment requirements imposed on the Utilities now and into the future. The future costs of complying with these requirements could be material to our or the Utilities' results of operations or financial position.

On September 15, 2009, the EPA announced that it had completed a multi-year study of power plant wastewater discharges and concluded that current regulations have not kept pace with changes in the electric power industry since the regulations were issued in 1982, including addressing impacts to wastewater discharge from operation of air pollution control equipment. As a result, the EPA has announced that it plans to revise the regulations that govern wastewater discharge, which may result in operational changes and additional compliance costs in the future. The outcome of this matter cannot be predicted.

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.

A number of states, environmental groups and others sought judicial review of the July 2004 rule. In 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, and the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. Several parties filed petitions for writ of certiorari to the U.S. Supreme Court. On April 1, 2009, the U.S. Supreme Court issued its opinion holding that the EPA, in selecting the "best technology" pursuant to Section 316(b), does have the authority to reject technology when its costs are "wholly disproportionate" to the benefits expected. Also, the U.S. Supreme Court held that EPA's site-specific variance procedure (contained in the July 2004 rule) was permissible in that the procedure required testing to determine whether costs would be "significantly greater than" the benefits before a variance would be considered. As a result of these 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 after it is established by the EPA. Costs of compliance with a revised or new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our cost estimates to comply with the July 2004 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

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. As discussed under "Other Matters – Regulatory Environment," on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national REPS. The U.S. Senate is considering similar proposals. Final legislation will depend upon changes made during the legislative process to the provisions and the manner in which key provisions are implemented, including for the regulation of carbon. In addition, the Obama administration has begun the process of regulating GHG emissions through use of the Clean Air Act. On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. On December 15, 2009, the EPA announced that six GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the Clean Air Act. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of final legislation, if enacted, and additional regulation resulting from other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate GHG emissions that would be presented to the legislature no earlier than January 2010. The FDEP is currently in the process of studying GHG policy options and the potential economic impacts, but it has not developed a regulation for the consideration of the legislature. As discussed under "Clean Smokestacks Act," on July 31, 2009, the governor of North Carolina signed into law a bill that may impact PEC's Clean Smokestacks Act compliance plans. While state-level study groups have been active in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect on February 16, 2005, the United States has not adopted it. In December 2009, the United Nations Framework Convention on Climate Change convened the 15th Conference of the Parties to conduct further negotiations on GHG emissions reductions. At the conclusion of the conference, a number of the parties, including the United States, entered into a nonbinding accord calling upon the parties to submit emission reduction targets for 2020 to the United Nations Framework Convention on Climate Change Secretariat by the end of January 2010. On January 28, 2010, President Obama submitted a proposal to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future Congressional action.

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol, potential new international treaties or federal or state 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.

Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review those denials of waiver requests. On June 30, 2009, the EPA granted California's waiver request, enabling the state to enforce its GHG emissions standards for new motor vehicles, beginning with the current model year. Additional states may set similar standards as a result of the decision. The impact of this development cannot be predicted.

On September 22, 2009, the EPA issued the final GHG emissions reporting rule, which establishes a national protocol for the reporting of annual GHG emissions. Facilities that emit greater than 25,000 metric tons per year of GHGs must report emissions by March 31 of each year beginning in 2011 for year 2010 emissions. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

SYNTHETIC FUELS TAX CREDITS

Historically, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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 synthetic fuels tax credit program expired at the end of 2007, and the synthetic fuels businesses were abandoned and reclassified to discontinued operations.

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code 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 one-year carry back period and a 20-year carry forward period.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, of which $1.179 billion has been used through December 31, 2009, to offset regular federal income tax liability and $712 million is being carried forward as deferred tax credits.

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

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 22D.

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 MD&A 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" and "Other Matters."

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" 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, commercial paper and its revolving credit agreement 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 to and from each other.

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 facility, long-term debt, preferred stock and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

Cash Flows from Operations

In 2009, net cash provided by operating activities increased when compared to 2008. The $222 million increase in operating cash flow was primarily due to a $258 million increase in the recovery of deferred fuel costs due to higher fuel rates in 2009, $67 million in lower net income tax payments and a $63 million decrease in inventory purchases primarily driven by lower coal prices. These impacts were partially offset by $163 million of pension and other benefits contributions made in 2009.

In 2008, net cash provided by operating activities increased when compared to 2007. The $43 million increase in operating cash flow was primarily due to a $79 million increase in cash receipts from a wholesale customer due to the expiration of a prepayment agreement; income tax impacts including $80 million in lower income tax payments; a $57 million increase from accounts payable and payables to affiliates, largely driven by the timing of payments; a $45 million increase from timing of customer collections; and a $32 million increase from net interest payments. These impacts were partially offset by a $119 million decrease in the recovery of fuel costs, largely driven by an under-recovery of fuels costs in 2008, and a $109 million increase in inventory purchases, primarily coal, driven by higher prices.

Investing Activities

In 2009, net cash used by investing activities increased $121 million when compared with 2008. The increase was primarily due to a $94 million increase in advances to affiliated companies and a $79 million increase in gross property additions, partially offset by a $57 million decrease in nuclear fuel additions. Property additions are primarily for normal construction activity and ongoing capital expenditures related to environmental compliance programs.

In 2008, net cash used by investing activities increased $150 million when compared with 2007. The increase was primarily due to a $79 million increase from changes in advances to affiliated companies and a $75 million decrease in net proceeds from 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.

Financing Activities

Net cash used by financing activities increased $77 million for 2009 when compared to 2008. The increase in net cash used by financing activities was primarily due to the $200 million in dividends paid to the Parent in 2009, the $110 million net repayment of commercial paper in 2009, the $110 million issuance of commercial paper in 2008, and the $100 million increase in the payment at maturity of long-term debt in 2009 compared to 2008. These impacts were partially offset by a $273 million increase in the proceeds from the issuance of long-term debt in 2009 compared to 2008, as well as the $154 million repayment of advances from affiliates in 2008.

Net cash used by financing activities decreased $146 million for 2008 when compared to 2007. The decrease in net cash used by financing activities was primarily due to $322 million in net proceeds from the issuance of long-term debt in 2008, $143 million in dividends paid to the Parent in 2007, and outstanding commercial paper issuances of $110 million, offset by a $308 million change in advances from affiliated companies and a $100 million increase in the retirement of long-term debt.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding money pool balance and for general corporate purposes.

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

On March 12, 2008, PEC amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEC's RCA is now scheduled to expire on June 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 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

On November 18, 2008, PEC, the Parent, as a well-known seasoned issuer, and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See "Credit Facilities and Registration Statements.")

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.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2010, 2011 and 2012 are approximately $1.5 billion to $1.6 billion, $1.6 billion and $1.4 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation and upgrade existing facilities as discussed in Progress Energy "Capital Expenditures."

PEC expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contributions of equity from the Parent. In addition, PEC has a $450 million credit facility that supports 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 toward the end of the next decade. This approach will require PEC to make significant capital investments. See Progress Energy "Introduction – Strategy" for additional information. 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.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

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

	2009	2008
Common stock equity	**55.2%**	53.8%
Preferred stock	**0.7%**	0.8%
Total debt	**44.1%**	45.4%

See the discussion of PEC's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEC's debt and credit facility.

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, 2009.

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. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts in the following table are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding PEC's contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs.

The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2009, 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 11)	$3,715	$6	$500	$400	$2,809
Interest payments on long-term debt[b]	2,041	180	361	275	1,225
Capital lease obligations (See Note 22B)	16	2	4	10	–
Operating leases[c] (See Note 22B)	800	25	41	96	638
Fuel and purchased power[d] (See Note 22A)	9,823	1,445	2,374	1,946	4,058
Other purchase obligations (See Note 22A)	630	381	213	30	6
Minimum pension funding requirements [e]	573	55	255	164	99
Other postretirement benefits[f] (See Note 16A)	200	15	34	39	112
Uncertain tax positions[g] (See Note 14)	–	–	–	–	–
Other commitments[h]	105	13	26	26	40
Total	$17,903	$2,122	$3,808	$2,986	$8,987

(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, 2009.

(c) Amounts include certain related executory cost commitments.

(d) 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 certain purchased power costs are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

(e) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(f) Represents projected benefit payments for a total of 10 years related to PEC's postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

(g) Uncertain tax positions of $59 million are not reflected in this table as PEC cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of PEC's unrecognized tax benefits will decrease by up to approximately $10 million during the 12-month period ending December 31, 2010, due to expected settlements.

(h) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $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 MD&A 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" and "Other Matters."

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" 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, equity contributions from the Parent, commercial paper and its revolving credit agreement 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 to and from each other.

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 facility, long-term debt, preferred stock and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

Cash Flows from Operations

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.086 billion increase in operating cash flow was primarily due to a $365 million increase in the recovery of deferred fuel costs due to higher fuel rates; a $323 million payment made in 2008 to counterparties for collateral associated with derivative contracts and $190 million net refunds of cash collateral in 2009. See discussion of PEF's fuel cost recovery in Progress Energy "Future Liquidity and Capital Resources." The change in derivative collateral assets was primarily driven by the relative fair values of our commodity derivative instruments (See Note 17A).

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $748 million decrease in operating cash flow was primarily due to a $331 million decrease in the recovery of fuel costs driven by the under-recovery of higher fuels costs in 2008; $323 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $47 million in net refunds of cash collateral in 2007; and an $87 million increase in inventory purchases, primarily driven by coal price increases and an increase in emission allowances purchases. See discussion of PEF's fuel cost recovery in Progress Energy "Future Liquidity and Capital Resources." The change in derivative collateral assets was primarily driven by the relative fair values of our commodity derivative instruments (See Note 17A).

Investing Activities

In 2009, net cash used by investing activities increased $89 million when compared with 2008. The increase in cash used by investing activities was primarily due to a $149 million decrease in settlements of advances to affiliates and a $35 million increase in nuclear fuel additions, partially offset by a $103 million decrease in property additions. The decrease in property additions was driven by decreases in environmental compliance spending and completion of the Bartow Plant repowering project, partially offset by an increase in expenditures for nuclear projects.

In 2008, net cash used by investing activities increased $37 million when compared with 2007. The increase in cash used by investing activities was primarily due to a $338 million increase in capital expenditures for utility property additions, partially offset by a $298 million decrease from changes in advances to affiliated companies. The increase in capital expenditures for utility property additions was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility, which was placed in service in 2007.

Financing Activities

Net cash provided by financing activities decreased $995 million for 2009 when compared to 2008. The decrease in cash provided by financing activities was primarily due to PEF's $1.475 billion in net proceeds from issuance of long-term debt in 2008, outstanding commercial paper issuances of $371 million in 2008, and repayment of commercial paper outstanding of $371 million in 2009, partially offset by receipts of $620 million in contributions from the Parent in 2009 and $532 million long-term debt retirements in 2008.

Net cash provided by financing activities increased $781 million for 2008 when compared to 2007. The increase in cash provided by financing activities was primarily due to PEF's $1.475 billion in net proceeds from issuance of long-term debt and outstanding commercial paper issuances of $371 million in 2008, partially offset by $739 million in net proceeds from the issuance of $750 million of long-term debt in 2007 and a $443 million increase in long-term debt retirements.

In 2009, PEF did not issue or retire long-term debt.

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, PEF amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEF's RCA is now scheduled to expire on March 28, 2011.

On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

On November 18, 2008, PEF; the Parent, as a well-known seasoned issuer; and PEC filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See "Credit Facilities and Registration Statements.")

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.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2010, 2011 and 2012 are approximately $0.9 billion to $1.0 billion, $0.9 billion, and $0.7 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and add environmental control facilities as discussed in Progress Energy "Capital Expenditures." PEF's estimated capital requirements include potential nuclear construction expenditures for Levy. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we anticipate amending the EPC agreement (See discussion in Progress Energy "Other Matters – Nuclear – Potential New Construction"), and the forecasted capital expenditures reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time, and, accordingly, are not included in forecasted capital expenditures. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions. Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

PEF expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contributions of equity from the Parent. In addition, PEF has a $450 million credit facility that supports 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.

At December 31, 2009, the current portion of PEF's long-term debt was $300 million, which we expect to fund with long-term debt issued in 2010.

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. This approach will require PEF to make significant capital investments. 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.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

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

	2009	2008
Common stock equity	**49.1%**	41.1%
Preferred stock	**0.4%**	0.4%
Total debt	**50.5%**	58.5%

See the discussion of PEF's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEF's debt and credit facility.

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, 2009.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties (See Note 17). Both PEC and PEF also have limited counterparty exposure for commodity hedges (primarily gas and oil hedges) by spreading concentration risk over a number of counterparties.

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 NDT 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

As part of our debt portfolio management and daily cash management, we have variable rate long-term debt and typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 9 percent and 18 percent of consolidated debt had variable rates at December 31, 2009 and 2008, respectively.

Based on our variable rate long-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $10 million. Based on our short-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an insignificant annual pre-tax interest expense change.

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 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 GAAP, 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, 2009 and 2008, 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 forward contracts, the tables present notional amounts and weighted-average interest rates by contractual mandatory termination dates for 2010 to 2014 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

December 31, 2009 (dollars in millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**	**Fair Value December 31, 2009**
Fixed-rate long-term debt	$306	$1,000	$950	$825	$300	$7,864	$11,245	$12,126
Average interest rate	4.53%	6.96%	6.67%	4.96%	6.05%	6.13%	6.12%	
Variable-rate long-term debt	$100	–	–	–	–	$861	$961	$961
Average interest rate	0.73%	–	–	–	–	0.45%	0.48%	
Debt to affiliated trust[(a)]	–	–	–	–	–	$309	$309	$315
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[(b)]	$75	$150	$100	–	–	–	$325	$19
Average pay rate	3.48%	4.03%	4.07%	–	–	–	3.91%	
Average receive rate	[(c)]	[(c)]	[(c)]	–	–	–	[(c)]	

(a) FPC Capital I – Quarterly Income Preferred Securities.
(b) Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(c) Rate is 3-month London Inter Bank Offered Rate (LIBOR), which was 0.25% at December 31, 2009.

During January 2010, Progress Energy entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, including $75 million notional at PEF.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million notional at PEC and $75 million notional at PEF.

December 31, 2008 (dollars in millions)	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$–	$306	$1,000	$950	$825	$6,265	$9,346	$9,909
Average interest rate	–	4.53%	6.96%	6.67%	4.96%	6.21%	6.17%	
Variable-rate long-term debt	–	$100	–	$100	–	$861	$1,061	$1,061
Average interest rate	–	5.20%	–	2.52%	–	1.90%	2.27%	
Debt to affiliated trust[(a)]	–	–	–	–	–	$309	$309	$290
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[(b)]	$450	–	–	–	–	–	$450	$(65)
Average pay rate	4.26%	–	–	–	–	–	4.26%	
Average receive rate	[(c)]	–	–	–	–	–	[(c)]	

(a) FPC Capital I – Quarterly Income Preferred Securities.
(b) Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(c) Rate is 3-month LIBOR, which was 1.43% at December 31, 2008.

At December 31, 2008, Progress Energy had $450 million notional of open forward starting swaps, including $250 million notional at PEC. At December 31, 2007, Progress Energy had $200 million notional of open forward starting swaps, all at PEC.

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, 2009 and 2008, the fair value of these funds was $1.367 billion and $1.089 billion, respectively, including $871 million and $672 million, respectively, for PEC and $496 million and $417 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, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively. A hypothetical 10 percent increase in the December 31, 2009 market price would result in a $2 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

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 physical commodity contracts are not derivatives or qualify as normal purchases or sales. 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, 2009 and 2008, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

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

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.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2009, 2008 and 2007, PEC recorded a net realized loss of $76 million, a net realized gain of $2 million and a net realized loss of $9 million, respectively. During the years ended December 31, 2009, 2008 and 2007, PEF recorded a net realized loss of $583 million, a net realized gain of $172 million and a net realized loss of $46 million, respectively.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparty negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

At December 31, 2009, the fair value of PEC's commodity derivative instruments was recorded as a $28 million short-term derivative liability position included in derivative liabilities and a $62 million long-term derivative liability position included in other liabilities and deferred credits on the PEC Consolidated Balance Sheet. At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in other liabilities and deferred credits on the PEC Consolidated Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. PEC had a cash collateral asset included in prepayments and other current assets of $7 million and $18 million on the PEC Consolidated Balance Sheet at December 31, 2009 and 2008, respectively.

At December 31, 2009, the fair value of PEF's commodity derivative instruments was recorded as an $11 million short-term derivative asset position included in prepayments and other current assets, a $9 million long-term derivative asset position included in other assets and deferred debits, a $161 million short-term derivative liability position included in current derivative liabilities, and a $174 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in prepayments and other current assets, a $1 million long-term derivative asset position included in other assets and deferred debits, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the PEF Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. PEF's cash collateral asset included in derivative collateral posted on the PEF Balance Sheet was $139 million at December 31, 2009, compared to $335 million at December 31, 2008.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2009 and 2008, 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 2009, 2008 and 2007.

At December 31, 2009 and 2008, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

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 NDT funds and changes in energy-related commodity prices.

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

INTEREST RATE RISK

The following tables provide information at December 31, 2009 and 2008, about PEC's interest rate risk sensitive instruments:

December 31, 2009 (dollars in millions)	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value December 31, 2009
Fixed-rate long-term debt	$6	$–	$500	$400	$–	$2,189	$3,095	$3,352
Average interest rate	6.30%	–	6.50%	5.13%	–	5.69%	5.75%	
Variable-rate long-term debt	–	–	–	–	–	$620	$620	$620
Average interest rate	–	–	–	–	–	0.45%	0.45%	
Interest rate forward contracts[(a)]	–	–	$100	–	–	–	$100	$8
Average pay rate	–	–	4.07%	–	–	–	4.07%	
Average receive rate	–	–	(b)	–	–	–	(b)	

(a) Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(b) Rate is 3-month LIBOR, which was 0.25% at December 31, 2009.

At December 31, 2009, PEC had $100 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2008 (dollars in millions)	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$–	$6	$–	$500	$400	$1,990	$2,896	$3,070
Average interest rate	–	6.30%	–	6.50%	5.13%	5.86%	5.87%	
Variable-rate long-term debt	–	–	–	–	–	$620	$620	$620
Average interest rate	–	–	–	–	–	2.01%	2.01%	
Interest rate forward contracts[(a)]	$250	–	–	–	–	–	$250	$(35)
Average pay rate	4.18%	–	–	–	–	–	4.18%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
(b) Rate is 3-month LIBOR, which was 1.43% at December 31, 2008.

At December 31, 2008 and 2007, PEC had $250 million notional and $200 million notional, respectively, of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

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 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 NDT funds, and changes in energy-related commodity prices.

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

INTEREST RATE RISK

The following tables provide information at December 31, 2009 and 2008, about PEF's interest rate risk sensitive instruments:

December 31, 2009 (dollars in millions)	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value December 31, 2009
Fixed-rate long-term debt	$300	$300	$–	$425	$–	$2,925	$3,950	$4,252
Average interest rate	4.50%	6.65%	–	4.80%	–	6.06%	5.85%	
Variable-rate long-term debt	–	–	–	–	–	$241	$241	$241
Average interest rate	–	–	–	–	–	0.47%	0.47%	
Interest rate forward contracts[(a)]	$75	–	–	–	–	–	$75	$5
Average pay rate	3.48%	–	–	–	–	–	3.48%	
Average receive rate	[(b)]	–	–	–	–	–	[(b)]	

[(a)] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[(b)] Rate is 3-month LIBOR, which was 0.25% at December 31, 2009.

During January 2010, PEF entered into a $75 million notional 10-year forward starting swap to mitigate exposure to interest rate risk in anticipation of future debt issuances.

At December 31, 2009, PEF had $75 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2008 (dollars in millions)	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$–	$300	$300	$–	$425	$2,925	$3,950	$4,305
Average interest rate	–	4.50%	6.65%	–	4.80%	6.06%	5.85%	
Variable-rate long-term debt	–	–	–	–	–	$241	$241	$241
Average interest rate	–	–	–	–	–	1.63%	1.63%	

At December 31, 2008 and 2007, PEF had no open forward starting swaps.

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, 4 through 7, 9 through 14, 16 through 18, 20 through 22 and 24
PEF	1, 2, 4 through 7, 9 through 14, 16 through 18, 20 through 22 and 24

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) as of December 31, 2009 and 2008, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 Progress Energy, Inc. and its subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, 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.

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 as of December 31, 2009, 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 26, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina

February 26, 2010

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data) Years ended December 31	**2009**	2008	2007
Operating revenues	**$9,885**	$9,167	$9,153
Operating expenses			
Fuel used in electric generation	**3,752**	3,021	3,145
Purchased power	**911**	1,299	1,184
Operation and maintenance	**1,894**	1,820	1,842
Depreciation, amortization and accretion	**986**	839	905
Taxes other than on income	**557**	508	501
Other	**13**	(3)	30
Total operating expenses	**8,113**	7,484	7,607
Operating income	**1,772**	1,683	1,546
Other income (expense)			
Interest income	**14**	24	34
Allowance for equity funds used during construction	**124**	122	51
Other, net	**6**	(17)	(7)
Total other income, net	**144**	129	78
Interest charges			
Interest charges	**718**	679	605
Allowance for borrowed funds used during construction	**(39)**	(40)	(17)
Total interest charges, net	**679**	639	588
Income from continuing operations before income tax	**1,237**	1,173	1,036
Income tax expense	**397**	395	334
Income from continuing operations	**840**	778	702
Discontinued operations, net of tax	**(79)**	58	(206)
Net income	**761**	836	496
Net (income) loss attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Net income attributable to controlling interests	**$757**	$830	$504
Average common shares outstanding – basic	**279**	262	257
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	**$2.99**	$2.95	$2.70
Discontinued operations attributable to controlling interests, net of tax	**(0.28)**	0.22	(0.74)
Net income attributable to controlling interests	**$2.71**	$3.17	$1.96
Dividends declared per common share	**$2.480**	$2.465	$2.445
Amounts attributable to controlling interests			
Income from continuing operations attributable to controlling interests, net of tax	**$836**	$773	$693
Discontinued operations attributable to controlling interests, net of tax	**(79)**	57	(189)
Net income attributable to controlling interests	**$757**	$830	$504

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

PROGRESS ENERGY, INC.
CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2009	2008
ASSETS		
Utility plant		
Utility plant in service	**$28,918**	$26,326
Accumulated depreciation	**(11,576)**	(11,298)
Utility plant in service, net	**17,342**	15,028
Held for future use	**47**	38
Construction work in progress	**1,790**	2,745
Nuclear fuel, net of amortization	**554**	482
Total utility plant, net	**19,733**	18,293
Current assets		
Cash and cash equivalents	**725**	180
Receivables, net	**800**	867
Inventory	**1,325**	1,239
Regulatory assets	**142**	533
Derivative collateral posted	**146**	353
Income taxes receivable	**145**	194
Prepayments and other current assets	**248**	154
Total current assets	**3,531**	3,520
Deferred debits and other assets		
Regulatory assets	**2,179**	2,567
Nuclear decommissioning trust funds	**1,367**	1,089
Miscellaneous other property and investments	**438**	446
Goodwill	**3,655**	3,655
Other assets and deferred debits	**333**	303
Total deferred debits and other assets	**7,972**	8,060
Total assets	**$31,236**	$29,873
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 281 million and 264 million shares issued and outstanding, respectively	**$6,873**	$6,206
Unearned ESOP shares (1 million shares)	**(12)**	(25)
Accumulated other comprehensive loss	**(87)**	(116)
Retained earnings	**2,675**	2,622
Total common stock equity	**9,449**	8,687
Noncontrolling interests	**6**	6
Total equity	**9,455**	8,693
Preferred stock of subsidiaries	**93**	93
Long-term debt, affiliate	**272**	272
Long-term debt, net	**11,779**	10,387
Total capitalization	**21,599**	19,445
Current liabilities		
Current portion of long-term debt	**406**	–
Short-term debt	**140**	1,050
Accounts payable	**835**	912
Interest accrued	**206**	167
Dividends declared	**175**	164
Customer deposits	**300**	282
Derivative liabilities	**190**	493
Accrued compensation and other benefits	**167**	193
Other current liabilities	**239**	225
Total current liabilities	**2,658**	3,486
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**1,196**	818
Accumulated deferred investment tax credits	**117**	127
Regulatory liabilities	**2,510**	2,181
Asset retirement obligations	**1,170**	1,471
Accrued pension and other benefits	**1,339**	1,594
Capital lease obligations	**221**	231
Derivative liabilities	**240**	269
Other liabilities and deferred credits	**186**	251
Total deferred credits and other liabilities	**6,979**	6,942
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$31,236**	$29,873

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2009	2008	2007
Operating activities			
Net income	**$761**	$836	$496
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**1,135**	957	1,026
Deferred income taxes and investment tax credits, net	**220**	411	177
Deferred fuel cost (credit)	**290**	(333)	117
Deferred income	–	–	(128)
Allowance for equity funds used during construction	**(124)**	(122)	(51)
Loss (gain) on sales of assets	**2**	(75)	(29)
Other adjustments to net income	**269**	135	212
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**26**	233	(186)
Inventory	**(99)**	(237)	(11)
Derivative collateral posted	**200**	(340)	55
Prepayments and other current assets	**3**	7	35
Income taxes, net	**(14)**	(169)	(275)
Accounts payable	**(26)**	77	(40)
Other current liabilities	**(42)**	(103)	81
Other assets and deferred debits	**11**	(44)	(198)
Accrued pension and other benefits	**(285)**	(39)	(91)
Other liabilities and deferred credits	**(56)**	24	62
Net cash provided by operating activities	**2,271**	1,218	1,252
Investing activities			
Gross property additions	**(2,295)**	(2,333)	(1,973)
Nuclear fuel additions	**(200)**	(222)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**1**	72	675
Purchases of available-for-sale securities and other investments	**(2,350)**	(1,590)	(1,413)
Proceeds from available-for-sale securities and other investments	**2,314**	1,534	1,452
Other investing activities	**(2)**	(2)	30
Net cash used by investing activities	**(2,532)**	(2,541)	(1,457)
Financing activities			
Issuance of common stock	**623**	132	151
Dividends paid on common stock	**(693)**	(642)	(627)
Payments of short-term debt with original maturities greater than 90 days	**(29)**	(176)	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	–	29	176
Net (decrease) increase in short-term debt	**(981)**	1,096	25
Proceeds from issuance of long-term debt, net	**2,278**	1,797	739
Retirement of long-term debt	**(400)**	(877)	(324)
Cash distributions to noncontrolling interests	**(6)**	(85)	(10)
Other financing activities	**14**	(26)	65
Net cash provided by financing activities	**806**	1,248	195
Net increase (decrease) in cash and cash equivalents	**545**	(75)	(10)
Cash and cash equivalents at beginning of year	**180**	255	265
Cash and cash equivalents at end of year	**$725**	$180	$255
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	**$701**	$612	$585
Income taxes, net of refunds	**87**	152	176
Significant noncash transactions			
Capital lease obligation incurred	–	–	182
Accrued property additions	**252**	334	329
Asset retirement obligation additions and estimate revisions	**(384)**	14	–

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

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CHANGES in TOTAL EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling Interests	Total Equity
Balance, December 31, 2006	**256**	**$5,791**	**$(50)**	**$(49)**	**$2,567**	**$10**	**$8,269**
Net income		–	–	–	504	(8)	496
Other comprehensive income		–	–	15	–	–	15
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 ($2.445 per share)		–	–	–	(631)	–	(631)
Sale of subsidiary shares to noncontrolling interests		–	–	–	–	37	37
Distributions to noncontrolling interests		–	–	–	–	(10)	(10)
Contributions from noncontrolling interests		–	–	–	–	52	52
Other transactions		–	–	–	–	3	3
Balance, December 31, 2007	**260**	**6,028**	**(37)**	**(34)**	**2,438**	**84**	**8,479**
Net income		–	–	–	830	6	836
Other comprehensive loss		–	–	(82)	–	–	(82)
Issuance of shares	4	131	–	–	–	–	131
Stock options exercised		1	–	–	–	–	1
Allocation of ESOP shares		13	12	–	–	–	25
Stock-based compensation expense		33	–	–	–	–	33
Dividends ($2.465 per share)		–	–	–	(646)	–	(646)
Distributions to noncontrolling interests		–	–	–	–	(85)	(85)
Contributions from noncontrolling interests		–	–	–	–	2	2
Other transactions		–	–	–	–	(1)	(1)
Balance, December 31, 2008	**264**	**6,206**	**(25)**	**(116)**	**2,622**	**6**	**8,693**
Net income[(a)]		**–**	**–**	**–**	**757**	**–**	**757**
Other comprehensive income		**–**	**–**	**29**	**–**	**–**	**29**
Issuance of shares	**17**	**623**	**–**	**–**	**–**	**–**	**623**
Allocation of ESOP shares		**8**	**13**	**–**	**–**	**–**	**21**
Stock-based compensation expense		**36**	**–**	**–**	**–**	**–**	**36**
Dividends ($2.480 per share)		**–**	**–**	**–**	**(704)**	**–**	**(704)**
Distributions to noncontrolling interests		**–**	**–**	**–**	**–**	**(1)**	**(1)**
Other transactions		**–**	**–**	**–**	**–**	**1**	**1**
Balance, December 31, 2009	**281**	**$6,873**	**$(12)**	**$(87)**	**$2,675**	**$6**	**$9,455**

(a) Consolidated net income of $761 million includes $4 million attributable to preferred shareholders of subsidiaries, which is not a component of total equity and is excluded from the table above.

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	2009	2008	2007
Net income	**$761**	$836	$496
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $4, $2 and $3, respectively)	**6**	3	4
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $3, $1 and $1, respectively)	**4**	1	2
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(10), $24 and $8, respectively)	**16**	(37)	(13)
Net unrecognized items on pension and other postretirement benefits (net of tax (expense) benefit of $(1), $29 and $(16), respectively)	**2**	(49)	23
Other (net of tax benefit of $-, $1 and $3, respectively)	**1**	–	(1)
Other comprehensive income (loss)	**29**	(82)	15
Comprehensive income	**790**	754	511
Comprehensive (income) loss attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Comprehensive income attributable to controlling interests	**$786**	$748	$519

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) as of December 31, 2009 and 2008, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 included 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 Progress Energy Carolinas, Inc. and its subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, 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 26, 2010

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

CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	2009	2008	2007
Operating revenues	**$4,627**	$4,429	$4,385
Operating expenses			
Fuel used in electric generation	**1,680**	1,346	1,381
Purchased power	**229**	346	302
Operation and maintenance	**1,072**	1,030	1,024
Depreciation, amortization and accretion	**470**	518	519
Taxes other than on income	**210**	198	192
Other	**–**	(5)	(2)
Total operating expenses	**3,661**	3,433	3,416
Operating income	**966**	996	969
Other income (expense)			
Interest income	**5**	12	21
Allowance for equity funds used during construction	**33**	27	10
Other, net	**(18)**	4	6
Total other income, net	**20**	43	37
Interest charges			
Interest charges	**207**	219	215
Allowance for borrowed funds used during construction	**(12)**	(12)	(5)
Total interest charges, net	**195**	207	210
Income before income tax	**791**	832	796
Income tax expense	**277**	298	295
Net income	**514**	534	501
Net loss attributable to noncontrolling interests, net of tax	**2**	–	–
Net income attributable to controlling interests	**516**	534	501
Preferred stock dividend requirement	**(3)**	(3)	(3)
Net income available to parent	**$513**	$531	$498

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

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

CONSOLIDATED BALANCE SHEETS

(in millions)

December 31	2009	2008
ASSETS		
Utility plant		
Utility plant in service	$16,297	$15,698
Accumulated depreciation	(7,520)	(7,352)
Utility plant in service, net	8,777	8,346
Held for future use	11	3
Construction work in progress	702	660
Nuclear fuel, net of amortization	396	376
Total utility plant, net	9,886	9,385
Current assets		
Cash and cash equivalents	35	18
Receivables, net	442	502
Receivables from affiliated companies	33	29
Notes receivable from affiliated companies	204	55
Inventory	677	633
Deferred fuel cost	88	207
Income taxes receivable	38	98
Prepayments and other current assets	61	28
Total current assets	1,578	1,570
Deferred debits and other assets		
Regulatory assets	873	1,243
Nuclear decommissioning trust funds	871	672
Miscellaneous other property and investments	199	197
Other assets and deferred debits	95	98
Total deferred debits and other assets	2,038	2,210
Total assets	$13,502	$13,165
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	$2,108	$2,083
Unearned ESOP common stock	(12)	(25)
Accumulated other comprehensive loss	(27)	(35)
Retained earnings	2,588	2,278
Total common stock equity	4,657	4,301
Noncontrolling interests	3	4
Total equity	4,660	4,305
Preferred stock	59	59
Long-term debt, net	3,703	3,509
Total capitalization	8,422	7,873
Current liabilities		
Current portion of long-term debt	6	–
Short-term debt	–	110
Accounts payable	355	377
Payables to affiliated companies	72	82
Interest accrued	70	59
Customer deposits	95	82
Derivative liabilities	29	82
Accrued compensation and other benefits	86	99
Other current liabilities	50	74
Total current liabilities	763	965
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,258	1,111
Accumulated deferred investment tax credits	110	115
Regulatory liabilities	1,293	987
Asset retirement obligations	801	1,122
Accrued pension and other benefits	708	856
Other liabilities and deferred credits	147	136
Total deferred credits and other liabilities	4,317	4,327
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$13,502	$13,165

See Notes to Progress Energy Carolinas, Inc. 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	**2009**	2008	2007
Operating activities			
Net income	**$514**	$534	$501
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**585**	616	608
Deferred income taxes and investment tax credits, net	**64**	204	41
Deferred fuel cost (credit)	**187**	(71)	48
Allowance for equity funds used during construction	**(33)**	(27)	(10)
Other adjustments to net income	**132**	45	(37)
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**42**	(61)	(16)
Receivables from affiliated companies	**(4)**	13	(15)
Inventory	**(56)**	(119)	(10)
Prepayments and other current assets	**11**	4	(17)
Income taxes, net	**50**	(116)	(37)
Accounts payable	**(18)**	42	33
Payables to affiliated companies	**(10)**	11	(37)
Other current liabilities	**(19)**	34	(29)
Other assets and deferred debits	**17**	7	(28)
Accrued pension and other benefits	**(181)**	(31)	(49)
Other liabilities and deferred credits	**2**	(24)	72
Net cash provided by operating activities	**1,283**	1,061	1,018
Investing activities			
Gross property additions	**(839)**	(760)	(757)
Nuclear fuel additions	**(122)**	(179)	(184)
Purchases of available-for-sale securities and other investments	**(696)**	(682)	(603)
Proceeds from available-for-sale securities and other investments	**642**	626	622
Changes in advances to affiliated companies	**(149)**	(55)	24
Other investing activities	**1**	8	6
Net cash used by investing activities	**(1,163)**	(1,042)	(892)
Financing activities			
Dividends paid on preferred stock	**(3)**	(3)	(3)
Dividends paid to parent	**(200)**	–	(143)
Net (decrease) increase in short-term debt	**(110)**	110	–
Proceeds from issuance of long-term debt, net	**595**	322	–
Retirement of long-term debt	**(400)**	(300)	(200)
Changes in advances from affiliated companies	**–**	(154)	154
Contributions from parent	**15**	15	21
Other financing activities	**–**	(16)	(1)
Net cash used by financing activities	**(103)**	(26)	(172)
Net increase (decrease) in cash and cash equivalents	**17**	(7)	(46)
Cash and cash equivalents at beginning of year	**18**	25	71
Cash and cash equivalents at end of year	**$35**	$18	$25
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	**$171**	$193	$210
Income taxes, net of refunds	**144**	211	291
Significant noncash transactions			
Accrued property additions	**91**	99	87
Asset retirement obligation additions and estimate revisions	**(386)**	(3)	–

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

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

CONSOLIDATED STATEMENTS of CHANGES in TOTAL EQUITY

(in millions)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Common Stock	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling interests	Total Equity
Balance, December 31, 2006	**160**	**$2,010**	**$(50)**	**$(1)**	**$1,404**	**$4**	**$3,367**
Net income		–	–	–	501	–	501
Other comprehensive loss		–	–	(9)	–	–	(9)
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)**	**1,745**	**4**	**3,756**
Net income		–	–	–	534	–	534
Other comprehensive loss		–	–	(25)	–	–	(25)
Stock-based compensation expense		13	–	–	–	–	13
Allocation of ESOP shares		16	12	–	–	–	28
Preferred stock dividends at stated rates		–	–	–	(3)	–	(3)
Tax benefit dividend		–	–	–	2	–	2
Balance, December 31, 2008	**160**	**2,083**	**(25)**	**(35)**	**2,278**	**4**	**4,305**
Net income		**–**	**–**	**–**	**516**	**(2)**	**514**
Other comprehensive income		**–**	**–**	**8**	**–**	**–**	**8**
Stock-based compensation expense		**15**	**–**	**–**	**–**	**–**	**15**
Allocation of ESOP shares		**10**	**13**	**–**	**–**	**–**	**23**
Dividends paid to parent		**–**	**–**	**–**	**(200)**	**–**	**(200)**
Preferred stock dividends at stated rates		**–**	**–**	**–**	**(3)**	**–**	**(3)**
Tax benefit dividend		**–**	**–**	**–**	**(3)**	**–**	**(3)**
Other transactions		**–**	**–**	**–**	**–**	**1**	**1**
Balance, December 31, 2009	**160**	**$2,108**	**$(12)**	**$(27)**	**$2,588**	**$3**	**$4,660**

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

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2009**	2008	2007
Net income	**$514**	$534	$501
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $2 and $1, respectively)	**3**	1	–
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(3), $17 and $4, respectively)	**5**	(26)	(5)
Other (net of tax benefit of $1)	**–**	–	(4)
Other comprehensive income (loss)	**8**	(25)	(9)
Comprehensive income	**522**	509	492
Comprehensive loss attributable to noncontrolling interests, net of tax	**2**	–	–
Comprehensive income attributable to controlling interests	**$524**	$509	$492

See Notes to Progress Energy Carolinas, Inc. 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) as of December 31, 2009 and 2008, 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, 2009. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 included 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 as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, 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 26, 2010

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

(in millions) Years ended December 31	**2009**	2008	2007
Operating revenues	**$5,251**	$4,731	$4,749
Operating expenses			
Fuel used in electric generation	**2,072**	1,675	1,764
Purchased power	**682**	953	882
Operation and maintenance	**839**	813	834
Depreciation, amortization and accretion	**502**	306	366
Taxes other than on income	**347**	309	309
Other	**7**	(5)	8
Total operating expenses	**4,449**	4,051	4,163
Operating income	**802**	680	586
Other income (expense)			
Interest income	**4**	9	9
Allowance for equity funds used during construction	**91**	95	41
Other, net	**5**	(10)	(2)
Total other income, net	**100**	94	48
Interest charges			
Interest charges	**258**	236	185
Allowance for borrowed funds used during construction	**(27)**	(28)	(12)
Total interest charges, net	**231**	208	173
Income before income tax	**671**	566	461
Income tax expense	**209**	181	144
Net income	**462**	385	317
Preferred stock dividend requirement	**(2)**	(2)	(2)
Net income available to parent	**$460**	$383	$315

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

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

BALANCE SHEETS

(in millions) December 31	2009	2008
ASSETS		
Utility plant		
Utility plant in service	**$12,438**	$10,449
Accumulated depreciation	**(3,987)**	(3,885)
Utility plant in service, net	**8,451**	6,564
Held for future use	**36**	35
Construction work in progress	**1,088**	2,085
Nuclear fuel, net of amortization	**158**	106
Total utility plant, net	**9,733**	8,790
Current assets		
Cash and cash equivalents	**17**	19
Receivables, net	**356**	362
Receivables from affiliated companies	**8**	15
Inventory	**648**	606
Regulatory assets	**54**	326
Derivative collateral posted	**139**	335
Deferred income taxes	**115**	74
Prepayments and other current assets	**80**	65
Total current assets	**1,417**	1,802
Deferred debits and other assets		
Regulatory assets	**1,307**	1,324
Nuclear decommissioning trust funds	**496**	417
Miscellaneous other property and investments	**42**	37
Other assets and deferred debits	**105**	101
Total deferred debits and other assets	**1,950**	1,879
Total assets	**$13,100**	$12,471
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$1,744**	$1,116
Accumulated other comprehensive income (loss)	**3**	(1)
Retained earnings	**2,743**	2,284
Total common stock equity	**4,490**	3,399
Preferred stock	**34**	34
Long-term debt, net	**3,883**	4,182
Total capitalization	**8,407**	7,615
Current liabilities		
Current portion of long-term debt	**300**	–
Short-term debt	**–**	371
Notes payable to affiliated companies	**221**	72
Accounts payable	**451**	514
Payables to affiliated companies	**62**	55
Interest accrued	**72**	51
Customer deposits	**205**	200
Derivative liabilities	**161**	380
Accrued compensation and other benefits	**53**	65
Other current liabilities	**89**	63
Total current liabilities	**1,614**	1,771
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**767**	634
Accumulated deferred investment tax credits	**7**	12
Regulatory liabilities	**1,103**	1,076
Asset retirement obligations	**369**	349
Accrued pension and other benefits	**395**	494
Capital lease obligations	**208**	216
Derivative liabilities	**174**	209
Other liabilities and deferred credits	**56**	95
Total deferred credits and other liabilities	**3,079**	3,085
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$13,100**	$12,471

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

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

STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	**2009**	2008	2007
Operating activities			
Net income	**$462**	$385	$317
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**527**	320	385
Deferred income taxes and investment tax credits, net	**64**	130	(44)
Deferred fuel cost (credit)	**103**	(262)	69
Allowance for equity funds used during construction	**(91)**	(95)	(41)
Other adjustments to net income	**116**	40	77
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(15)**	(26)	(8)
Receivables from affiliated companies	**7**	(7)	3
Inventory	**(43)**	(122)	(35)
Derivative collateral posted	**190**	(323)	47
Prepayments and other current assets	**11**	(15)	25
Income taxes, net	**(75)**	–	3
Accounts payable	**(11)**	48	43
Payables to affiliated companies	**7**	(32)	(29)
Other current liabilities	**1**	(10)	35
Other assets and deferred debits	**4**	(8)	(44)
Accrued pension and other benefits	**(83)**	(24)	(20)
Other liabilities and deferred credits	**(37)**	52	16
Net cash provided by operating activities	**1,137**	51	799
Investing activities			
Gross property additions	**(1,449)**	(1,552)	(1,214)
Nuclear fuel additions	**(78)**	(43)	(44)
Purchases of available-for-sale securities and other investments	**(1,540)**	(782)	(640)
Proceeds from available-for-sale securities and other investments	**1,545**	784	640
Changes in advances to affiliated companies	–	149	(149)
Proceeds from sales of assets to affiliated companies	–	12	–
Other investing activities	**(6)**	(7)	5
Net cash used by investing activities	**(1,528)**	(1,439)	(1,402)
Financing activities			
Dividends paid on preferred stock	**(2)**	(2)	(2)
Net (decrease) increase in short-term debt	**(371)**	371	–
Proceeds from issuance of long-term debt, net	–	1,475	739
Retirement of long-term debt	–	(532)	(89)
Changes in advances from affiliated companies	**149**	72	(47)
Contributions from parent	**620**	–	–
Other financing activities	**(7)**	–	2
Net cash provided by financing activities	**389**	1,384	603
Net decrease in cash and cash equivalents	**(2)**	(4)	–
Cash and cash equivalents at beginning of year	**19**	23	23
Cash and cash equivalents at end of year	**$17**	$19	$23
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	**$228**	$205	$149
Income taxes, net of refunds	**184**	52	184
Significant noncash transactions			
Capital lease obligation incurred	–	–	182
Accrued property additions	**156**	231	238

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

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

	Common Stock Outstanding		Accumulated Other		Total
(in millions except shares outstanding)	Shares	Amount	Comprehensive (Loss) Income	Retained Earnings	Common Stock Equity
Balance, December 31, 2006	**100**	**$1,100**	**$(1)**	**$1,588**	**$2,687**
Net income		–	–	317	317
Other comprehensive loss		–	(7)	–	(7)
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**
Net income		–	–	385	385
Other comprehensive income		–	7	–	7
Stock-based compensation expense		7	–	–	7
~~Preferred stock dividends at stated rates~~		~~–~~	~~–~~	~~(2)~~	~~(2)~~
Balance, December 31, 2008	**100**	**1,116**	**(1)**	**2,284**	**3,399**
Net income		**–**	**–**	**462**	**462**
Other comprehensive income		**–**	**4**	**–**	**4**
Stock-based compensation expense		**8**	**–**	**–**	**8**
Contributions from parent		**620**	**–**	**–**	**620**
Preferred stock dividends at stated rates		**–**	**–**	**(2)**	**(2)**
Tax benefit dividend		**–**	**–**	**(1)**	**(1)**
Balance, December 31, 2009	**100**	**$1,744**	**$3**	**$2,743**	**$4,490**

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

(in millions) Years ended December 31	**2009**	2008	2007
Net income	**$462**	$385	$317
Other comprehensive income (loss)			
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(2), $(5) and $5, respectively)	4	7	(7)
Other comprehensive income (loss)	4	7	(7)
Comprehensive income	$466	$392	$310

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

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

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

PROGRESS ENERGY, INC.

The Parent is a holding company headquartered in Raleigh, N.C. 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 (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable 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), including GAAP for regulated operations. The financial statements 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 noncontrolling interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for noncontrolling interests 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, 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. 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 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by GAAP for regulated operations, 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.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under GAAP.

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 2008 and 2007 have been reclassified to conform to the 2009 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 (VIEs) for which we are the primary beneficiary. In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk that identifies which variable interest holder absorbs the majority of the financial risk and variability of the VIE. In performing this analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity. If the qualitative analysis is inconclusive, a specific quantitative analysis is performed.

In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance which makes significant changes to the model for determining who should consolidate a VIE and addresses how often this assessment should be performed. See Note 2 for further discussion regarding the new guidance, which requires all existing arrangements with VIEs to be evaluated, and any impacts of adoption accounted for as a cumulative-effect adjustment. The guidance is effective for us on January 1, 2010. We do not expect the adoption to have a significant impact on our or the Utilities' financial position, results of operations and cash flows.

PROGRESS ENERGY

In addition to the following variable interests listed for PEC, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2008 or 2009. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2009, we had no assets and $3 million of liabilities related to tax indemnifications provided to the buyer included in other liabilities and deferred credits on the Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the gain on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 22C for a general discussion of guarantees. See Note 22D for discussion of recent developments related to legal indemnifications.

PEC

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

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). PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2007 through 2009. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2009, PEC had assets of $39 million, substantially all of which was reflected in miscellaneous other property and investment, and $15 million in long-term debt, $3 million in other liabilities and deferred credits and $5 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase 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 $46 million, $44 million and $39 million in 2009, 2008 and 2007, 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 investment fund's 17 partnerships and the power plant owner are VIEs 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 provided by GAAP 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 power plant and the investment fund consolidating the 17 partnerships 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.

PEF

PEF has no significant variable interests in VIEs.

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 base revenues earned when service has been delivered but not billed by the end of the accounting period. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

Fuel expense includes fuel costs and 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)	**2009**	2008	2007
Progress Energy	**$333**	$295	$299
PEC	**108**	102	99
PEF	**225**	193	200

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of GAAP.

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 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 (AROs) 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.

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Balance Sheets. Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service.

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 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates 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 and froze North Carolina electric utility base rates for a five-year period, which ended in 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. In September 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks compliance costs (See Note 7B).

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with an original 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.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, 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.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

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. Income taxes are provided for as if PEC and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when the book and tax carrying amounts of assets and liabilities differ. 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 in the Consolidated Statements of Income.

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP 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 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 hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. 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, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. We do not accrue an estimate of 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 loss contingencies have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. 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. 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

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 equity 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.

2. NEW ACCOUNTING STANDARDS

Effective July 1, 2009, changes to the source of authoritative U.S. GAAP, the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC), are communicated through an Accounting Standards Update (ASU). ASUs will be published for all authoritative U.S. GAAP promulgated by the FASB, regardless of the form in which such guidance may have been issued prior to release of the FASB Codification (e.g., FASB Statements, FASB Staff Positions, etc.).

ASC 810 Consolidations

On January 1, 2009, we implemented ASC 810-10-65, which was previously referred to as Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." ASC 810-10-65 introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. The adoption of ASC 810-10-65 resulted in a retrospective change in presentation of the financial statements for all periods presented and additional disclosures but did not have a material impact on our or the Utilities' financial position or results of operations.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities." In January 2010, the FASB issued ASU 2009-17, "Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," which codified SFAS No. 167. This guidance makes significant changes to the model for determining who should consolidate a VIE, addresses how often this assessment should be performed, requires all existing arrangements with VIEs to be evaluated, and must be adopted through a cumulative-effect adjustment. This guidance is effective for us on January 1, 2010. See Note 1C for information regarding our implementation of ASU 2009-17 and its expected impact on our financial position and results of operations.

ASC 815-10-65 (SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133)"

On January 1, 2009, we implemented ASC 815-10-65, which was previously referred to as SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133." ASC 815-10-65 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 and its related interpretations and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. See Note 17 for information regarding our first quarter 2009 implementation of ASC 815-10-65. The adoption of ASC 815-10-65 did not have a material impact on our or the Utilities' financial position or results of operations.

ASC 260-10-45 (FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities)"

On January 1, 2009, we implemented ASC 260-10-45, which was previously referred to as FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." ASC 260-10-45 requires that certain unvested share-based payment awards (e.g., restricted stock) that contain nonforfeitable rights to dividends or dividend equivalents be included in the computation of earnings per share using the two-class method. ASC 260-10-45 requires a retrospective adjustment for all prior-period earnings per share data. The adoption of ASC 260-10-45 did not have a material impact on our or the Utilities' financial position, results of operations or earnings per share amounts.

Fair Value Measurement and Disclosures and Other-Than-Temporary Impairments

In April 2009, the FASB issued three FSPs for guidance on accounting for fair value measurement and other-than-temporary impairments.

ASC 820 includes the FSP previously referred to as FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," and provides guidance on determining fair value when market activity has decreased for an asset or liability. ASC 825-10-50, previously referred to as FSP FAS 107-1 and APB 28-1, "Interim Disclosures About Fair Value of Financial Instruments," increases the frequency of fair value disclosures required from annually to quarterly.

ASC 320 includes the FSPs previously referred to as FSP FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," and revises the recognition and reporting requirements for other-than-temporary impairments of debt securities and increases the frequency of disclosures for debt and equity securities. Under ASC 320, if an entity intends to sell an impaired debt security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, an other-than-temporary impairment must be recognized currently in earnings equal to the difference between the investment's amortized cost and its fair value at the balance sheet date.

The new guidance in ASC 820, ASC 825 and ASC 320 was effective for us during the three months ended June 30, 2009. The adoption resulted in additional disclosures but did not have a material impact on our or the Utilities' financial position or results of operations. See Note 13 for the disclosures resulting from the implementation of this guidance in 2009.

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends ASC 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 is effective for us on January 1, 2010, with certain disclosures effective for periods beginning January 1, 2011. The adoption of ASU 2010-06 will change certain disclosures in the notes to the financial statements, but will have no impact on our or the Utilities' financial position or results of operations.

ASC 715-20-65 (FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets")

In December 2008, the FASB issued ASC 715-20-65, previously referred to as FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets," which requires additional disclosures on the investment allocation decision making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. ASC 715-20-65 was effective for us on December 31, 2009. The adoption of ASC 715-20-65 resulted in additional disclosures, but did not have a material impact on our or the Utilities' financial position or results of operations. See Note 16 for the information regarding our implementation of ASC 715-20-65.

ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)"

In September 2009, the FASB issued ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)," which provides additional guidance related to measuring the fair value of certain alternative investments, such as interests in hedge funds, private equity funds, real estate funds, venture capital funds, offshore fund vehicles, and funds of funds. ASU 2009-12 allows reporting entities to use net asset value per share to estimate the fair value of certain investments as a practical expedient and requires disclosures by major category of investment about the attributes of the investments. ASU 2009-12 was effective for us on December 31, 2009. The adoption of ASU 2009-12 did not have a material impact on our or the Utilities' financial position or results of operations.

3. DIVESTITURES

We completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

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. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements 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 Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. 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.

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability of $16 million, and $4 million related to other legal and tax contingency adjustments. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of Terminals and the synthetic fuels businesses discontinued operations for the years ended December 31 were as follows.

(in millions)	2009	2008	2007
Revenues	$–	$17	$1,126
(Loss) earnings before income taxes and noncontrolling interest	$(125)	$8	$2
Income tax benefit, including tax credits	47	12	64
(Loss) earnings attributable to noncontrolling interests of Synthetic Fuels	–	(1)	17
Net (loss) earnings from discontinued operations attributable to controlling interests	(78)	19	83
Gain on disposal of discontinued operations, including income tax expense of $7	–	42	–
(Loss) earnings from discontinued operations attributable to controlling interests	$(78)	$61	$83

B. COAL MINING BUSINESSES

On March 7, 2008, we sold the remaining operations of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels) subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets. During 2009, we recognized a $1 million loss as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the Coal Mining as discontinued operations. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	2009	2008	2007
Revenues	$–	$2	$28
Loss before income taxes	$(2)	$(13)	$(17)
Income tax benefit	1	4	6
Net loss from discontinued operations	(1)	(9)	(11)
Gain on disposal of discontinued operations, including income tax expense of $2	–	7	–
Loss from discontinued operations attributable to controlling interests	$(1)	$(2)	$(11)

C. CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary, Progress Energy 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. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of a previously recorded impairment, respectively.

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 represented 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 represented 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. During 2008 and 2009, we recognized a $5 million loss and a $1 million gain, respectively, as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense was 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 year ended December 31, 2007, was $11 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Revenues	**$–**	$–	$407
Loss before income taxes	**$(1)**	$(5)	$(449)
Income tax benefit	**2**	2	166
Net earnings (loss) from discontinued operations	**1**	(3)	(283)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $7, respectively	**–**	(2)	18
Earnings (loss) from discontinued operations attributable to controlling interests	**$1**	$(5)	$(265)

D. OTHER DIVERSIFIED BUSINESSES

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses, primarily Progress Rail Services Corporation. We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2009, we recorded an after-tax loss on disposal of $1 million and after-tax gains of $3 million and $4 million for the years ended December 31, 2008 and 2007, respectively. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

E. 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 nonrecourse 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. 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 year ended December 31, 2008. The note had an interest rate equal to the three-month London Inter Bank Offered 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 year ended December 31, 2008, based on the final value of the 2007 Section 29/45K tax credits.

During the year ended December 31, 2008, we recognized previously deferred 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 remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with GAAP for variable interest entities, but record a 100 percent noncontrolling interest.

4. 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	**2009**	2008	**2009**	2008	**2009**	2008
Production plant	7-43	**$16,042**	$14,117	**$9,579**	$9,249	**6,280**	$4,689
Transmission plant	17-75	**3,273**	2,970	**1,535**	1,457	**1,738**	1,513
Distribution plant	13-55	**8,376**	8,028	**4,499**	4,330	**3,877**	3,698
General plant and other	5-35	**1,227**	1,211	**684**	662	**543**	549
Utility plant in service		**$28,918**	$26,326	**$16,297**	$15,698	**$12,438**	$10,449

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 11).

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 9.2%, 9.2% and 8.8% in 2009, 2008 and 2007, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2009, 2008 and 2007.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.4% in 2009, 2008 and 2007, respectively. The depreciation provisions related to utility plant were $626 million, $578 million and $560 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2009, 2008 and 2007. The depreciation provisions related to utility plant were $328 million, $310 million and $303 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), 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% in 2009, 2008 and 2007. The depreciation provisions related to utility plant were $299 million, $268 million and $257 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C) and regulatory approved expenses (See Note 7C).

Nuclear fuel, net of amortization at December 31, 2009 and 2008, was $554 million and $482 million, respectively, for Progress Energy, $396 million and $376 million, respectively, for PEC and $158 million and $106 million, respectively, for PEF. The amount not yet in service at December 31, 2009 and 2008, was $308 million and $243 million, respectively, for Progress Energy, $175 million and $182 million, respectively, for PEC and $133 million and $61 million, respectively, for PEF. 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, was $159 million, $145 million and $139 million for the years ended December 31, 2009, 2008 and 2007, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income. Amortization of nuclear fuel costs for the years ended December 31, 2009, 2008 and 2007 was $134 million, $115 million and $110 million, respectively, for PEC and $25 million, $30 million and $29 million, respectively, for PEF.

PEF's construction work in progress related to certain nuclear projects has received regulatory treatment. At December 31, 2009, PEF reflected $296 million of construction work in progress, of which $274 million was reflected as a nuclear cost-recovery clause regulatory asset (See Note 7C) and $22 million was reflected as a deferred fuel regulatory asset. At December 31, 2008, PEF reflected $174 million of construction work in progress as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

B. 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 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:

2009 **(in millions)** **Subsidiary**	**Facility**	**Company Ownership Interest**	**Plant Investment**	**Accumulated Depreciation**	**Construction Work in Progress**
PEC	**Mayo**	**83.83%**	**$785**	**$282**	**$8**
PEC	**Harris**	**83.83%**	**3,207**	**1,651**	**28**
PEC	**Brunswick**	**81.67%**	**1,681**	**981**	**74**
PEC	**Roxboro Unit 4**	**87.06%**	**686**	**449**	**15**
PEF	**Crystal River Unit 3**	**91.78%**	**900**	**472**	**510**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**10**	**–**

2008 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$519	$278	$228
PEC	Harris	83.83%	3,187	1,603	21
PEC	Brunswick	81.67%	1,667	970	42
PEC	Roxboro Unit 4	87.06%	674	446	12
PEF	Crystal River Unit 3	91.78%	843	461	252
PEF	Intercession City Unit P11	66.67%	23	9	–

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.

C. ASSET RETIREMENT OBLIGATIONS

Primarily due to the impact of updated cost estimates, as discussed below, at December 31, 2009, PEC had no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant. At December 31, 2008, PEC's asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $28 million. At December 31, 2009 and 2008, PEF's asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $18 million and $19 million, respectively. At December 31, 2009 and 2008, additional PEF-related asset retirement costs, net of accumulated depreciation, of $114 million and $116 million, respectively, were recorded at Progress Energy as purchase accounting adjustments recognized when we purchased Florida Progress Corporation

(Florida Progress) in 2000. The fair value of funds set aside in the Utilities' NDT funds for the nuclear decommissioning liability totaled $871 million and $672 million at December 31, 2009 and 2008, respectively, for PEC and $496 million and $417 million, respectively, for PEF (See Notes 12 and 13). Net NDT 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 2009, 2008 and 2007. As discussed below, PEF has suspended its accrual for nuclear decommissioning. 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 do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense, were $106 million, $100 million and $96 million in 2009, 2008 and 2007, respectively, for PEC and $35 million, $33 million and $30 million in 2009, 2008 and 2007, respectively, for PEF.

During 2009, PEF submitted a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study is expected to have an insignificant impact on cost of removal expense in 2010.

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)	**2009**	2008	**2009**	2008	**2009**	2008
Removal costs	**$1,532**	$1,478	**$944**	$864	**$588**	$614
Nonirradiated decommissioning costs	**211**	146	**150**	84	**61**	62
Dismantlement costs	**123**	124	**–**	–	**123**	124
Non-ARO cost of removal	**$1,866**	$1,748	**$1,094**	$948	**$772**	$800

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris Nuclear Plant (Harris) Unit No. 1, in December 2009, which will be filed with the NCUC in the first quarter of 2010. PEC's estimate is 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 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion 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. See Note 7D for information about the NRC operating licenses held by PEC. Based on updated cost estimates, in 2009 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $27 million and $390 million, respectively, resulting in no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2009.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing (See Note 7C). However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF will not be required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF will be required to update the 2008 study with the most currently available escalation rates in 2010. 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 2008 dollars, is $751 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. See Note 7D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate and assumed operating license renewal, PEF increased its asset retirement cost and its ARO liability by approximately $19 million in 2008. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its planned 2010 nuclear decommissioning filing. 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 received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. PEF's reserve for fossil plant dismantlement was approximately $143 million and $145 million at December 31, 2009 and 2008, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended under the terms of ~~previous base rate settlement agreements.~~

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $27 million and $21 million at December 31, 2009 and 2008, respectively, at PEC and $27 million and $24 million at December 31, 2009 and 2008, respectively, at PEF.

Additionally, PEC and PEF have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $1 million at December 31, 2009 and 2008, at PEC and $6 million at December 31, 2009 and 2008, at PEF. For PEC, closure work related to the landfill commenced in 2009 and should be completed in 2010.

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.

The following table presents the changes to the AROs during the years ended December 31, 2009 and 2008. Revisions to prior estimates of the PEC and PEF regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

(in millions)	Progress Energy	PEC	PEF
Asset retirement obligations at January 1, 2008	$1,378	$1,063	$315
Additions	7	1	6
Accretion expense	79	62	17
Revisions to prior estimates	7	(4)	11
Asset retirement obligations at December 31, 2008	1,471	1,122	349
Accretion expense	**83**	**65**	**18**
Revisions to prior estimates	**(384)**	**(386)**	**2**
Asset retirement obligations at December 31, 2009	**$1,170**	**$801**	**$369**

D. 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 this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. 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 $28 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 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 the plant, 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 $12.595 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 $117.5 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 $17.5 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 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified 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).

5. RECEIVABLES

Income taxes receivable and interest income receivables are not included in receivables. These amounts are included in prepayments and other current assets or shown separately on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Trade accounts receivable	**$581**	$648	**$291**	$350	**$288**	$298
Unbilled accounts receivable	**193**	182	**125**	120	**68**	62
Notes receivable	–	2	–	–	–	–
Derivatives accounts receivable	**2**	–	–	–	**2**	–
Other receivables	**42**	53	**34**	38	**8**	13
Allowance for doubtful receivables	**(18)**	(18)	**(8)**	(6)	**(10)**	(11)
Total receivables, net	**$800**	$867	**$442**	$502	**$356**	$362

6. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Fuel for production	**$667**	$614	**$304**	$287	**$363**	$327
Materials and supplies	**639**	588	**366**	338	**273**	250
Emission allowances	**18**	37	**6**	8	**12**	29
Other	**1**	–	**1**	–	**–**	–
Total inventory	**$1,325**	$1,239	**$677**	$633	**$648**	$606

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy of $24 million and $23 million at December 31, 2009 and 2008, respectively.

~~Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on~~ the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $39 million, $8 million and $31 million, respectively, at December 31, 2009. Long-term emission allowances for Progress Energy, PEC and PEF were $61 million, $14 million and $47 million, respectively, at December 31, 2008.

7. REGULATORY MATTERS

A. REGULATORY ASSETS AND LIABILITIES

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. 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 GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations 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 would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

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 expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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

Progress Energy

(in millions)	2009	2008
Deferred fuel cost – current (Notes 7B and 7C)	**$105**	$335
Nuclear deferral (Note 7C)	**37**	190
Environmental	**–**	8
Total current regulatory assets	**142**	533
Deferred fuel cost – long-term (Note 7B)[a]	**62**	130
Nuclear deferral (Note 7C) [a]	**239**	–
Deferred impact of ARO (Note 4C)[b]	**99**	348
Income taxes recoverable through future rates[b]	**264**	193
Loss on reacquired debt[c]	**35**	37
Storm deferral (Note 7C)[d]	**10**	16
Postretirement benefits (Note 16)[e]	**945**	1,042
Derivative mark-to-market adjustment (Note 17A)[f]	**436**	697
Environmental (Notes 7C and 21A)[g]	**24**	31
Accrued vacation[a]	**10**	32
DSM / Energy-efficiency deferral (Note 7B)[h]	**19**	9
Other	**36**	32
Total long-term regulatory assets	**2,179**	2,567
Environmental (Note 7C)	**(24)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(3)**	(6)
Total current regulatory liabilities	**(27)**	(6)
Non-ARO cost of removal (Note 4C)[b]	**(1,866)**	(1,748)
Deferred impact of ARO (Note 4C)[b]	**(150)**	(198)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(295)**	(28)
Derivative mark-to-market adjustment (Note 17A)[f]	**(20)**	(26)
Storm reserve (Note 7C)[g]	**(136)**	(129)
Other	**(43)**	(52)
Total long-term regulatory liabilities	**(2,510)**	(2,181)
Net regulatory (liabilities) assets	**$(216)**	$913

PEC

(in millions)	2009	2008
Deferred fuel cost – current (Note 7B)	**$88**	$207
Deferred fuel cost – long-term (Note 7B)[a]	**62**	130
Deferred impact of ARO (Note 4C)[b]	**92**	343
Income taxes recoverable through future rates[b]	**76**	62
Loss on reacquired debt[c]	**15**	16
Postretirement benefits (Note 16)[e]	**483**	522
Derivative mark-to-market adjustment (Note 17A)[f]	**88**	96
Accrued vacation[a]	**10**	32
DSM / Energy-efficiency deferral[h]	**19**	9
Other	**28**	33
Total long-term regulatory assets	**873**	1,243
Non-ARO cost of removal (Note 4C)[b]	**(1,094)**	(948)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(181)**	(21)
Other	**(18)**	(18)
Total long-term regulatory liabilities	**(1,293)**	(987)
Net regulatory (liabilities) assets	**$(332)**	$463

PEF

(in millions)	2009	2008
Deferred fuel cost – current (Note 7C)	**$17**	$128
Nuclear deferral (Note 7C)	**37**	190
Environmental	**–**	8
Total current regulatory assets	**54**	326
Nuclear deferral (Note 7C)[a]	**239**	–
Income taxes recoverable through future rates[b]	**188**	131
Loss on reacquired debt[c]	**20**	21
Storm deferral (Note 7C)[d]	**10**	14
Postretirement benefits (Note 16)[e]	**462**	520
Derivative mark-to-market adjustment (Note 17A)[f]	**348**	601
Environmental (Notes 7C and 21A)[g]	**19**	21
Other	**21**	16
Total long-term regulatory assets	**1,307**	1,324
Environmental (Note 7C)	**(24)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(3)**	(6)
Total current regulatory liabilities	**(27)**	(6)
Non-ARO cost of removal (Note 4C)[b]	**(772)**	(800)
Deferred impact of ARO (Note 4C)[b]	**(30)**	(76)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(114)**	(7)
Derivative mark-to-market adjustment (Note 17A)[f]	**(20)**	(26)
Storm reserve (Note 7C)[g]	**(136)**	(129)
Other	**(31)**	(38)
Total long-term regulatory liabilities	**(1,103)**	(1,076)
Net regulatory assets	**$231**	$568

The recovery and amortization periods for these regulatory assets and (liabilities) at 2009 are as follows:

(a) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

(b) Asset retirement and removal liabilities are recorded and income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and adjusted following completion of the related activities.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

(d) Recorded and recovered or amortized as approved by the FERC over a period not exceeding five years.

(e) Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 7C).

(f) Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After settlement of the derivatives and the fuel is consumed, the realized gains or losses are passed through the fuel cost-recovery clause.

(g) Recovered as environmental remediation or storm restoration expenses are incurred.

(h) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

(i) Related to unrealized gains and losses on nuclear decommissioning trust funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

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 of 12.75 percent. In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from 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 flexibility in the amount of annual amortization recorded from none up to $174 million per year.

For the years ended December 31, 2008 and 2007, PEC recognized Clean Smokestacks Act amortization of $15 million and $34 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC did not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful lives of the assets.

See Note 21B for additional information about the Clean Smokestacks Act.

FUEL COST RECOVERY

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On May 28, 2009, PEC jointly filed a settlement agreement with the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million. On June 19, 2009, the SCPSC approved the settlement agreement. The decrease was effective July 1, 2009, and decreased residential electric bills by $2.08 per 1,000 kilowatt-hours (kWh), or 2.0 percent, for fuel cost recovery. At December 31, 2009, PEC's South Carolina under-recovered deferred fuel balance was $2 million.

On June 4, 2009, and as updated on August 17, 2009, PEC filed with the NCUC for a $14 million decrease in the fuel rate charged to its North Carolina ratepayers, driven by declining fuel prices. On November 16, 2009, the NCUC approved PEC's request. Effective December 1, 2009, residential electric bills decreased by $0.45 per 1,000 kWh, or 0.4 percent, for fuel cost recovery. At December 31, 2009, PEC's North Carolina under-recovered deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

Comprehensive energy legislation enacted by North Carolina in 2007 allows PEC to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs 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. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of the DSM and energy-efficiency filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results. At December 31, 2009, PEC's deferred North Carolina DSM and energy-efficiency costs totaled $15 million.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency rider to recover all program costs, including the recovery of appropriate incentives for investing in such programs. On November 14, 2008, the NCUC issued an order allowing PEC to implement the rates requested in PEC's November 14, 2008 revision to its initial application. The new rates, subject to true-up to the final order, were implemented on December 1, 2008, increasing residential electrical bills by $0.74 per 1,000 kWh, or 0.8 percent. As a result of settlement agreements entered into in 2007 and resulting regulatory proceedings, the NCUC ordered PEC to recalculate rates and submit to the NCUC for approval. The 2009 impact of these revised rates was immaterial.

On June 4, 2009, and as updated on August 17, 2009, PEC requested the NCUC approve a $1 million increase in the DSM and energy-efficiency rate charged to its North Carolina ratepayers. Due to changes in how the costs are allocated among customer classes, the request results in a decrease to the residential rate, while increasing rates for other customer classes. The rate change was approved on an interim basis effective December 1, 2009, and decreased residential electric bills by $0.19 per 1,000 kWh, or 0.2 percent.

On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. On May 6, 2009, the SCPSC approved the Stipulation Agreement and issued a directive requiring PEC to file for approval of all proposed DSM and energy-efficiency programs. On May 11, 2009, in accordance with the SCPSC directive, PEC filed its programs for approval and an application for a cost-recovery rider for PEC's DSM and energy-efficiency programs. On June 10, 2009, SCPSC approved the proposed DSM and energy-efficiency programs and the cost-recovery rider application, on a provisional basis pending a review of the cost-recovery rider by the South Carolina Office of Regulatory Staff. The rate increase was effective July 1, 2009, and increased residential electric bills by $0.79 per 1,000 kWh, or 0.8 percent, for DSM and energy-efficiency cost recovery. We cannot predict the outcome of this matter. At December 31, 2009, PEC's deferred South Carolina DSM and energy-efficiency costs totaled $4 million.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

Beginning in 2009, PEC is required to file an annual North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC has selected APX, Inc. as the vendor for implementation of a statewide REC tracking system. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, will participate in the registry. Rates for the NC REPS clause are set based on projected costs with true-up provisions. On June 4, 2009 and as updated August 17, 2009, PEC filed with the NCUC for a $7 million increase in the NC REPS rate charged to its North Carolina ratepayers. On November 12, 2009, the NCUC approved PEC's request effective December 1, 2009. PEC's residential electric bills increased by $0.29 per month, or 0.3 percent, for renewable energy portfolio standard (REPS) cost recovery.

ENVIRONMENTAL COMPLIANCE COST RECOVERY

On February 11, 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental operation and maintenance expenses that PEC incurs in connection with its environmental compliance control facilities. At December 31, 2009, PEC's South Carolina environmental compliance cost-recovery balance was $5 million.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery were $415 million and $585 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 $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. PEC reached the minimum amount of $415 million of cost recovery by December 31, 2008, and no additional depreciation expense from accelerated cost recovery was recorded in 2009. The South Carolina aggregate minimum and maximum amounts of cost recovery were $115 million and $165 million, respectively. Prior to the SCPSC's 2008 approval to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets, PEC had recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction. As a result of the SCPSC's 2008 approval, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful lives of the assets. No additional depreciation expense from accelerated cost recovery for the South Carolina jurisdiction was recorded in 2009, 2008 or 2007.

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-based 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-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on July 1, 2008. On May 15, 2009, PEC filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $4 million.

On October 13, 2008, the NCUC issued a Certificate of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 600-MW combined cycle dual fuel-capable generating facility at its Richmond County generation site to provide additional generating and transmission capacity to meet the growing energy demands of southern and eastern North Carolina. PEC expects that the new generating and transmission capacity will be online by the second quarter of 2011.

North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. On August 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility would be in service by January 2013. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units, with a combined generating capacity of approximately 400 MW, that are currently in operation at the site. This will result in approximately 550 MW of incremental capacity. On September 21, 2009, the Public Staff recommended that the NCUC issue the certificate subject to additional conditions as follows: the facility be constructed and operated in accordance with all applicable laws and regulations, PEC file with the NCUC a progress report and any revisions in the cost estimates on an annual basis, PEC permanently cease operation of the three coal-fired units immediately upon completion and placement into service of the facility and that the NCUC clarify that the issuance of the certificate does not constitute approval of the final costs associated with construction of the facility. On October 1, 2009, the NCUC issued a notice of decision stating it found good cause to issue an order granting PEC the certificate subject to the four conditions proposed by the Public Staff as well as adding a condition that PEC submit for NCUC approval a plan to retire additional coal-fired capacity reasonably proportionate to the 550 MW of incremental capacity. On October 22, 2009, the NCUC issued its order granting PEC the certificate to construct the 950-MW facility.

On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC intends to continue to depreciate these units using the current depreciation rates as on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study.

On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. PEC projects that the generating facility would be in service by late 2013 or early 2014. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units currently in operation at the site that do not have scrubbers. These units have a combined generating capacity of approximately 600 MW

C. PEF RETAIL RATE MATTERS

BASE RATES

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. Based on actual energy sales, the interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009. The changes increased residential bills by approximately $4.52 per 1,000 kWh, or 3.7 percent. On July 2, 2009, Florida's Office of Public Counsel (OPC), the Florida Industrial Power Users Group, the attorney general, the Florida Retail Federation and PCS Phosphate filed a petition protesting portions of the FPSC approval. On August 31, 2009, the FPSC issued an order to consolidate the interim and limited base rate relief increase and the base rate proposal. PEF's remaining base rate request as filed by PEF would have increased residential bills by approximately $9.66 per 1,000 kWh, or 7.6 percent, effective January 1, 2010. A hearing was held on this matter September 21, 2009 – October 1, 2009. On October 27, 2009, the FPSC held a hearing to determine if the voting of pending rate cases should be delayed until new FPSC appointees took office in January 2010. During the hearing, the FPSC voted to delay the rulings on the appropriate level of revenue requirements until January 11, 2010.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual operating and maintenance (O&M) costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options in Florida.

FUEL COST RECOVERY

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced residential customers' fuel charges by $6.90 per 1,000 kWh, or 5.0 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On August 10, 2006, Florida's OPC filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers alleged excessive past fuel-recovery charges and SO_2 allowance costs during the period 1996 to 2005. 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 October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC 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. The refund was returned to ratepayers in 2008 through a reduction of prior year under-recovered fuel costs. 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). On February 2, 2009, the OPC filed direct testimony alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of \$61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 Plants. During the hearing on the matter, the OPC reduced the alleged excessive fuel costs to \$33 million before interest. On June 30, 2009, the FPSC approved a refund of \$8 million to PEF's ratepayers to be paid over a 12-month period beginning January 1, 2010, and ordered PEF to file a report by September 2009 regarding the prospective application of PEF's coal procurement plan and the prudence of PEF's coal procurement actions. In compliance with the FPSC order, PEF filed the coal procurement status report on September 14, 2009. For the year ended December 31, 2009, PEF recorded a pre-tax other operating expense of \$8 million, an immaterial amount of interest and an associated regulatory liability included within PEF's deferred fuel cost at December 31, 2009. PEF chose not to appeal the FPSC's order.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by \$105 million, thereby decreasing residential electric bills by \$3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. This decrease is due to a decrease of \$9.89 per 1,000 kWh for the projected recovery of fuel costs, partially offset by an increase of \$6.55 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause (CCRC). The decrease in projected fuel costs is due primarily to a decrease in the price of natural gas and a change in the expected average fuel costs. An extended biennial nuclear outage at CR3 for an uprate project in 2009 contributed to higher projected fuel costs for 2009; however, anticipated changes in the generation mix for 2010 are expected to result in lower average fuel costs and contributed to the projected decrease in 2010 fuel costs. The increase in the CCRC is primarily the result of projected costs to be incurred in 2010 under the nuclear cost-recovery rule discussed below for the proposed nuclear plant in Levy County, Fla. (Levy) and an under-recovery of purchased power costs in 2009. On October 23, 2009, as a result of the October 16, 2009 FPSC vote in the nuclear cost-recovery matter discussed more fully below, PEF filed a \$3 million cost adjustment with the FPSC, which reduced the CCRC rate by \$0.08 per 1,000 kWh from the original September 14, 2009 cost-adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

On August 28, 2009, PEF filed a request to increase the Environmental Cost Recovery Clause (ECRC) residential rate and the filing was updated on October 27, 2009. PEF is asking the FPSC to increase residential rates by \$2.25 per 1,000 kWh, or 1.8 percent. This would increase projected revenues by \$33 million. This increase is primarily due to the return on assets expected to be placed in service at the end of 2009. On September 14, 2009, PEF filed a request to increase the Energy Conservation Cost Recovery Clause (ECCR) residential rate by \$0.47 per 1,000 kWh, or 0.4 percent. This would increase projected revenues by \$4 million. This increase is due mainly to an increase in conservation program costs. The FPSC approved PEF's ECRC and ECCR clause filings on November 2, 2009, to be effective January 1, 2010.

NUCLEAR COST RECOVERY

Levy 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. 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 PEF's customers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 was approximately \$14 billion for generating facilities and approximately \$3 billion for associated transmission facilities. The FPSC issued the final order granting the petition for the Determination of Need for the proposed nuclear units on August 12, 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 Levy. PEF filed the petition to assist the FPSC in the timely and adequate review of the proposed project's costs recoverable under the 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 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for Levy, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced residential customers' nuclear cost-recovery charge by $7.80 per 1,000 kWh, or 5.7 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing, which would result in a nuclear cost-recovery charge of either $7.98 per 1,000 kWh for residential customers under PEF's alternate proposal, or $15.07 per 1,000 kWh if the FPSC did not approve PEF's alternate proposal. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million of revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. This revenue level results in a nuclear cost-recovery charge of $6.99 per 1,000 kWh, which represents a $2.68 increase per 1,000 kWh for residential customer bills. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

On October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule. Specifically, the FPSC clarified that (1) nuclear costs are deemed to be recovered up to the amount of FPSC-approved projections and (2) the deferral of unrecovered nuclear costs would accrue a carrying charge at PEF's approved AFUDC rate consistent with the requirements of FPSC's nuclear cost-recovery rule, which is fixed at the pre-tax AFUDC rate in effect as of June 12, 2007. Accordingly, PEF retrospectively assigned capacity revenues to match the FPSC-approved projected level of nuclear cost recovery as of September 30, 2009. Nuclear costs incurred in excess of original projections earn a carrying charge equal to the AFUDC rate. Prior to the FPSC clarification, PEF assigned capacity revenues to nuclear cost recovery based on actual costs incurred; any over- or under-recoveries of actual costs were deferred and earned a carrying charge equal to a commercial paper rate.

On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs as a part of PEF's proposed rate management plan. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of the 1) $198 million of capacity revenues and 2) the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

The FPSC has authorized alternative cost-recovery mechanisms for preconstruction and construction carrying costs of nuclear power plants. Accordingly, at December 31, 2009 and 2008, PEF reflected $276 million and $190 million, respectively, of nuclear-related costs as a regulatory asset, of which $274 million and $174 million, respectively, represents construction work in progress (See Note 4A). Of the total $276 million of nuclear-related costs at December 31, 2009, $275 million related to Levy. The total $190 million of nuclear-related costs at December 31, 2008, was comprised of $181 million related to Levy and $9 million related to the CR3 uprate.

CR3 Uprate

On August 28, 2009, PEF filed a petition with the FPSC to approve a $17 million base rate increase for the phase II costs associated with the uprate of CR3. PEF's 2009 revenue requirements for recovery of the phase II costs were included in the CCRC. As permitted under the nuclear cost-recovery rule, PEF's phase III costs associated with the CR3 uprate are currently being recovered through the CCRC discussed above. On October 29, 2009, the FPSC Staff recommended that the FPSC approve PEF's request with minor modifications and that the new rates be implemented at the same time as PEF implements new base rates from its rate case proceeding. On October 30, 2009, PEF filed an amended petition requesting this rate change be implemented effective January 1, 2010. On December 1, 2009, the FPSC approved an increase in base rates for residential customers by $0.57 per 1,000 kWh, or 0.4 percent.

STORM COST RECOVERY

In 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 four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007, PEF recorded the remaining amortization of $75 million associated with the recovery of these storm costs.

During 2006, the FPSC approved a settlement agreement between PEF and 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 that began August 2007 to replenish its storm reserve. Additionally, the settlement agreement provided 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. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. The surcharge agreement expired in August 2008. At December 31, 2009 and 2008, PEF's storm reserve totaled $136 million and $129 million, respectively.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based 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-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on January 1, 2008. On May 15, 2009, PEF filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $2 million. In addition, one of PEF's large wholesale customers became subject to the new rate structure on September 1, 2009, increasing PEF's 2009 revenues by an additional $4 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense and the authorization to charge $33 million in estimated 2009 storm hardening expenses to its storm damage reserve. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC denied PEF's request related to the storm hardening expenses, but approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense will not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015.

D. NUCLEAR LICENSE RENEWALS

PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year renewal from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. At December 31, 2009 and 2008, 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. We perform our annual impairment test as of April 1 of each year. During the second quarter in 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired.

9. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2009 and 2008, we had 500 million shares of common stock authorized under our charter, of which 281 million shares and 264 million shares, respectively, were outstanding. For the years ended December 31, 2009, 2008 and 2007, we issued shares of common stock, primarily under a public offering and to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Progress Energy Investor Plus Plan (IPP). In addition, we periodically issue shares for our other benefit plans.

The following table presents information for our common stock issuances:

	Years Ended December 31,					
	2009		2008		2007	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**17.5**	**\$623**	3.7	\$132	3.7	\$151
Issuances under a public offering	**14.4**	**523**	–	–	–	–
Issuances to meet requirements of 401(k) and IPP	**2.5**	**100**	3.1	131	1.0	46

The shares issued under a public offering were issued on January 12, 2009, at a public offering price of \$37.50. We used \$100 million of the proceeds to reduce the Parent's revolving credit agreement (RCA) borrowings and the remainder was used for general corporate purposes.

Subsequent to December 31, 2009, the Parent issued approximately 3.6 million shares of common stock resulting in approximately \$136 million in proceeds through the IPP. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings (See Note 11B).

PEC

At December 31, 2009 and 2008, 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, 2009, there were no significant restrictions on the use of retained earnings. See Note 11B for additional dividend restrictions related to PEC.

PEF

At December 31, 2009 and 2008, 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, 2009, there were no significant restrictions on the use of retained earnings. See Note 11B 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, 2009 and 2008, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has a matching feature, 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 0.5 million and 1.1 million ESOP suspense shares at December 31, 2009 and 2008, respectively, with a fair value of $22 million and $45 million, respectively. ESOP shares allocated to plan participants totaled 13.0 million and 12.6 million at December 31, 2009 and 2008, respectively. Our matching compensation cost under the 401(k) is determined based on matching percentages 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 the matching component are typically met with shares in the same year incurred. Matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $13 million, $8 million and $23 million for the years ended December 31, 2009, 2008 and 2007, 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.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation which covers bargaining unit employees of PEF.

Total matching cost for both plans was approximately $41 million, $38 million and $34 million for the years ended December 31, 2009, 2008 and 2007, respectively.

PEC

PEC's matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $8 million, $5 million and $14 million for the years ended December 31, 2009, 2008 and 2007, respectively. Total matching cost was approximately $22 million, $21 million and $18 million for the years ended December 31, 2009, 2008 and 2007, respectively.

PEF

PEF's matching costs, which were met and will be met with shares released from the suspense account, totaled approximately \$3 million, \$1 million and \$4 million for the years ended December 31, 2009, 2008 and 2007, respectively. Total matching cost for both plans was approximately \$12 million, \$11 million and \$10 million for the years ended December 31, 2009, 2008 and 2007, 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 officers and 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, 2009, 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	1.6	\$43.99
Canceled	(0.1)	43.76
Exercised	–	–
Options outstanding, December 31	1.5	44.00
Options exercisable, December 31	1.5	44.00

The options outstanding and exercisable at December 31, 2009, had a weighted-average remaining contractual life of 3.03 years. Aggregate intrinsic value as of December 31, 2009, was not significant. The total intrinsic value of options exercised during the years ended December 31, 2009 and 2008, was not significant. Total intrinsic value of options exercised during the year ended December 31, 2007, was \$17 million.

Compensation cost for expense purposes is measured at the grant date based on the fair value of the award and is recognized over the vesting period. All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

Cash received from the exercise of stock options totaled \$105 million during the year ended December 31, 2007. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2007, was \$6 million. Cash received from the exercise of stock options for the years ended December 31, 2009 and 2008, was not significant.

PEC

All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

PEF

All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

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 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. In 2009, the PSSP was redesigned again, and shares issued under the revised plan use total shareholder return and earnings growth as two equally weighted performance measures. 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. We issue new shares of common stock to satisfy the requirements of the PSSP program. 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 paid in the years ended December 31, 2009, 2008 and 2007, were not significant.

A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2009, 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	1,118,604	$46.46
Granted	328,369	33.80
Vested	(419,366)	44.23
Paid[b]	(232,793)	50.55
Forfeited	(16,484)	44.27
Ending balance	778,330	45.49

(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.

For the years ended December 31, 2008 and 2007, the weighted-average grant date fair value of stock-settled performance shares granted was $42.41 and $50.70, respectively.

The Restricted Stock Award 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 included as shares outstanding in the basic earnings per share calculation.

A summary of the status of the nonvested restricted stock shares at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	192,101	$43.93
Granted	–	–
Vested	(50,297)	44.06
Forfeited	(6,500)	42.79
Ending balance	135,304	43.94

For the year ended December 31, 2007, the weighted-average grant date fair value of restricted stock granted was $49.54. There were no restricted stock shares granted in 2008.

The total fair value of restricted stock awards vested during the years ended December 31, 2009, 2008 and 2007, was $2 million, $3 million and $13 million, respectively. No cash was expended to purchase shares for 2009, and cash expended to purchase shares during 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program upon the rollout of the restricted stock unit (RSU) program in 2007.

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. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, 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 included as shares outstanding in the basic earnings per share calculation. Units are converted to shares upon vesting.

A summary of the status of nonvested RSUs at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	1,076,536	$46.86
Granted	644,231	33.91
Vested	(342,723)	47.18
Forfeited	(39,759)	41.54
Ending balance	1,338,285	43.46

The total fair value of RSUs vested during the year ended December 31, 2009, was $16 million. No cash was expended to purchase stock to satisfy RSU plan obligations in 2009, 2008 and 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $39 million for the year ended December 31, 2009, with a recognized tax benefit of $15 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $31 million with a recognized tax benefit of $12 million and $64 million, with a recognized tax benefit of $24 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2009, there was $31 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 1.56 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $24 million for the year ended December 31, 2009, with a recognized tax benefit of $9 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $18 million with a recognized tax benefit of $7 million and $38 million, with a recognized tax benefit of $15 million, for the years ended December 31, 2008 and 2007, 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 $15 million for the year ended December 31, 2009, with a recognized tax benefit of $6 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $13 million with a recognized tax benefit of $5 million and $21 million, with a recognized tax benefit of $8 million, for the years ended December 31, 2008 and 2007, respectively. 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, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of 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)	**2009**	2008	2007
Weighted-average common shares – basic	**279.4**	261.6	257.3
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.2
Weighted-average shares – fully diluted	**279.5**	261.7	257.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests 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 ESOP shares totaled 0.7 million, 1.2 million and 1.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. There were 1.5 million, 1.6 million and 0.1 million stock options outstanding at December 31, 2009, 2008 and 2007, 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) INCOME

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

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
(Loss) gain on cash flow hedges	**$(35)**	$(57)	**$(27)**	$(35)	**$3**	$(1)
Pension and other postretirement benefits	**(52)**	(58)	–	–	–	–
Other	–	(1)	–	–	–	–
Total accumulated other comprehensive (loss) income	**$(87)**	$(116)	**$(27)**	$(35)	**$3**	$(1)

10. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

At December 31, 2009 and 2008, preferred stock outstanding consisted of the following:

	Shares			
(dollars in millions, except share and per share data)	Authorized	Outstanding	Redemption 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

11. 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, 2009):

(in millions)		2009	2008
Parent			
Senior unsecured notes, maturing 2010-2039	6.50%	**$4,300**	$2,600
Draws on revolving credit agreement, expiring 2012		**—**	100
Unamortized premium and discount, net		**(7)**	(4)
Current portion of long-term debt		**(100)**	—
Long-term debt, net		**4,193**	2,696
PEC			
~~First mortgage bonds, maturing 2010-2038~~	~~5.60%~~	~~**2,525**~~	~~2,325~~
Pollution control obligations, maturing 2017-2024	0.80%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Miscellaneous notes	6.01%	**21**	22
Unamortized premium and discount, net		**(6)**	(7)
Current portion of long-term debt		**(6)**	—
Long-term debt, net		**3,703**	3,509
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	**3,800**	3,800
Pollution control obligations, maturing 2018-2027	0.47%	**241**	241
Medium-term notes, maturing 2028	6.75%	**150**	150
Unamortized premium and discount, net		**(8)**	(9)
Current portion of long-term debt		**(300)**	—
Long-term debt, net		**3,883**	4,182
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(37)**	(37)
Long-term debt, net		**272**	272
Progress Energy consolidated long-term debt, net		**$12,051**	$10,659

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.

On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to prefund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the following table, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

2009 **(in millions)**	**Description**	**Total**	**Outstanding[a]**	**Reserved[b]**	**Available**
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$ –**	**$177**	**$1,853**

2008 (in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
Parent	Five-year (expiring 5/3/12)	$1,130	$ 600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$ 600	$580	$850

(a) The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper balance with proceeds from the $950 million November 2009 issuance of Senior Notes.

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/Watch Negative by Moody's Investors Service, Inc. (Moody's) and BBB/Watch Negative by Standard & Poor's Rating Service (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+/Watch Negative 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/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

The following table summarizes short-term debt comprised of the short-term portion of outstanding RCA borrowings and our outstanding commercial paper, and related weighted-average interest rates at December 31:

(in millions)	**2009**		2008	
Parent	**0.49%**	**$140**	2.81%	$569
PEC	–	–	4.36%	110
PEF	–	–	4.41%	371
Total	**0.49%**	**$140**	3.54%	$1,050

The following table presents the aggregate maturities of long-term debt at December 31, 2009:

(in millions)	Progress Energy Consolidated	PEC	PEF
2010	$406	$6	$300
2011	1,000	–	300
2012	950	500	–
2013	825	400	425
2014	300	–	–
Thereafter	9,034	2,809	3,166
Total	$12,515	$3,715	$4,191

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent'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, 2009, 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]
Parent	68%	58%
PEC	65%	44%
PEF	65%	51%

[a] Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees 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 the Parent 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. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only 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 the Parent'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 the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither the Parent'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, 2009, the Parent had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by the Parent'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, 2009, 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 the 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, 2009, PEC's common stock equity was approximately 55.3 percent of total capitalization. At December 31, 2009, 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, 2009, 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 the 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, 2009, PEF's common stock equity was approximately 53.4 percent of total capitalization. At December 31, 2009, 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, 2009, PEC and PEF had a total of $3.194 billion and $4.041 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.

12. INVESTMENTS

A. INVESTMENTS

At December 31, 2009 and 2008, 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)	**2009**	2008	**2009**	2008	**2009**	2008
Nuclear decommissioning trust (See Notes 4C and 13)	**$1,367**	$1,089	**$871**	$672	**$496**	$417
Equity method investments[(a)]	**18**	22	**5**	9	**2**	2
Cost investments[(b)]	**5**	7	**4**	3	**–**	–
Company-owned life insurance[(c)]	**45**	49	**35**	34	**–**	–
Benefit investment trusts[(d)]	**191**	184	**90**	85	**35**	30
Marketable debt securities	**–**	1	**–**	1	**–**	–
Total	**$1,626**	$1,352	**$1,005**	$804	**$533**	$449

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

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

(c) Investments in company-owned life insurance approximate fair value due to the nature of the investment and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(d) Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 2009 and 2008, $152 million and $142 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF INVESTMENTS

We evaluate declines in value of investments under the criteria of GAAP. 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, other available-for-sale securities and equity and cost method investments. See Note 13 for additional information. There were no material other-than-temporary impairments in 2009, 2008 or 2007.

13. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.457 billion and $10.659 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $13.4 billion and $11.3 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 4C). NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at December 31, 2009 and 2008.

2009 (in millions)	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(22)**	**$306**	**$855**
Corporate debt securities	**(1)**	**5**	**71**
U.S. state and municipal debt securities	**(2)**	**3**	**118**
U.S. and foreign government debt securities	**(1)**	**8**	**197**
Money market funds and other securities	**–**	**–**	**161**
Total	**$(26)**	**$322**	**$1,402**

2008 (in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(93)	$134	$559
Corporate debt securities	(5)	–	53
U.S. state and municipal debt securities	(19)	4	233
U.S. and foreign government debt securities	(2)	11	171
Money market funds and other securities	(1)	–	123
Total	$(120)	$149	$1,139

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments; all of the unrealized losses and unrealized gains for 2009, and $118 million of the unrealized losses and $148 million of the unrealized gains for 2008, relate to the NDT funds. There were no material unrealized losses for the other available-for-sale debt securities held in benefit trusts at December 31, 2009 and 2008.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $209 million and $374 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$12
Due after one through five years	180
Due after five through 10 years	122
Due after 10 years	84
Total	$398

The following table presents selected information about our sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$1,275**	$1,092	$1,334
Realized gains	**26**	29	35
Realized losses	**87**	86	23

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, our proceeds from the sale of these securities were $399 million. For the years ended December 31, 2009 and 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2009, 2008 and 2007 for investments in these benefit investment 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, 2009 and 2008, 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 $3.709 billion and $3.509 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.0 billion and $3.7 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEC's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEC's nuclear plants (See Note 4C). NDT funds are presented on the Consolidated Balance Sheets at fair value.

The following table summarizes PEC's available-for-sale securities at December 31, 2009 and 2008.

2009 (in millions)	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(19)**	**$189**	**$555**
Corporate debt securities	**(1)**	**4**	**67**
U.S. state and municipal debt securities	**–**	**1**	**37**
U.S. and foreign government debt securities	**(1)**	**8**	**177**
Money market funds and other securities	**–**	**–**	**35**
Total	**$(21)**	**$202**	**$871**

2008 (in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(55)	$75	$334
Corporate debt securities	(2)	–	37
U.S. state and municipal debt securities	(6)	1	61
U.S. and foreign government debt securities	(1)	10	146
Money market funds and other securities	(1)	–	111
Total	$(65)	$86	$689

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2009 and 2008 relate to the NDT funds.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $121 million and $191 million, respectively.

At December 31, 2009, 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	142
Due after five through 10 years	93
Due after 10 years	44
Total	$287

The following table presents selected information about PEC's sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$602**	$579	$609
Realized gains	**9**	12	12
Realized losses	**36**	48	13

PEC's proceeds were primarily related to NDT funds. 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, 2009 and 2008, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.183 billion and $4.182 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.5 billion at December 31, 2009 and 2008.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEF's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEF's nuclear plant (See Note 4C). The NDT funds are presented on the Balance Sheets at fair value.

The following table summarizes PEF's available-for-sale securities at December 31, 2009 and 2008.

2009			
(in millions)	**Unrealized Losses**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$(3)**	**$117**	**$300**
Corporate debt securities	**–**	**1**	**4**
U.S. state and municipal debt securities	**(2)**	**2**	**80**
U.S. and foreign government debt securities	**–**	**–**	**13**
Money market funds and other securities	**–**	**–**	**99**
Total	**$(5)**	**$120**	**$496**

2008			
(in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
Equity securities	$(38)	$59	$225
Corporate debt securities	(2)	–	7
U.S. state and municipal debt securities	(13)	3	168
U.S. and foreign government debt securities	–	–	1
Money market funds and other securities	–	–	10
Total	$(53)	$62	$411

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2009 and 2008 relate to the NDT funds.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $56 million and $165 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$4
Due after one through five years	35
Due after five through 10 years	27
Due after 10 years	33
Total	$99

The following table presents selected information about PEF's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$559**	$394	$535
Realized gains	**14**	16	22
Realized losses	**50**	36	9

Previously, PEF invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, PEF's proceeds from the sale of these securities were $329 million. For the years ended December 31, 2009 and 2008, all of PEF's proceeds were related to NDT. 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, 2009 and 2008, PEF did not have any other securities.

B. FAIR VALUE MEASUREMENTS

GAAP 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). Fair value measurements require 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. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also 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 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 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 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.

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 December 31, 2009. 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				
Nuclear decommissioning trust funds				
Equity	$855	$–	$–	$855
Corporate debt	–	71	–	71
U.S. state and municipal debt	–	117	–	117
U.S. and foreign government debt	62	128	–	190
Money market funds and other	1	133	–	134
Total nuclear decommissioning trust funds	918	449	–	1,367
Commodity and interest rate derivatives	–	39	–	39
Other marketable securities				
U.S. state and municipal debt	–	1	–	1
U.S. and foreign government debt	–	7	–	7
Money market and other	16	27	–	43
Total assets	$934	$523	$–	$1,457
Liabilities				
Commodity and interest rate derivatives	$–	$(386)	$(39)	$(425)
CVO derivatives	–	(15)	–	(15)
Total liabilities	$–	$(401)	$(39)	$(440)

PEC

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$555	$–	$–	$555
Corporate debt	–	67	–	67
U.S. state and municipal debt	–	37	–	37
U.S. and foreign government debt	52	125	–	177
Money market and other	1	34	–	35
Total nuclear decommissioning trust funds	608	263	–	871
Commodity and interest rate derivatives	–	8	–	8
Other marketable securities	1	–	–	1
Total assets	$609	$271	$–	$880
Liabilities				
Commodity and interest rate derivatives	$–	$(63)	$(27)	$(90)

PEF

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$300	$–	$–	$300
Corporate debt	–	4	–	4
U.S. state and municipal debt	–	80	–	80
U.S. and foreign government debt	10	3	–	13
Money market funds and other	–	99	–	99
Total nuclear decommissioning trust funds	310	186	–	496
Commodity and interest rate derivatives	–	25	–	25
Other marketable securities	1	–	–	1
Total assets	$311	$211	$–	$522
Liabilities				
Commodity and interest rate derivatives	$–	$(323)	$(12)	$(335)

The determination of the fair values above incorporates various factors, 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 17 for discussion of risk management activities and derivative transactions.

NDT funds reflect the assets of the Utilities' nuclear decommissioning trusts. 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 primarily represent available-for-sale debt securities used to fund certain employee benefit costs.

We issued Contingent Value Obligations (CVOs) in connection with the acquisition of Florida Progress, as discussed in Note 15. 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 for the 12 months ended December 31, 2009.

Progress Energy

(in millions)	
Derivatives, net at January 1, 2009	$(41)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(13)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	15
Derivatives, net at December 31, 2009	$(39)

PEC

(in millions)	
Derivatives, net at January 1, 2009	$(22)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(7)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	2
Derivatives, net at December 31, 2009	$(27)

PEF

(in millions)	
Derivatives, net at January 1, 2009	$(19)
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	13
Derivatives, net at December 31, 2009	$(12)

Substantially all 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 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. Transfers into Level 3 are measured at the beginning of the period, and transfers out of Level 3 are measured at the end of the period.

14. INCOME TAXES

We provide deferred income taxes for temporary 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 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. 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)	2009	2008
Deferred income tax assets		
ARO liability	**$127**	$264
Derivative instruments	**159**	298
Income taxes refundable through future rates	**225**	111
Pension and other postretirement benefits	**508**	544
Other	**374**	340
Federal income tax credit carry forward	**712**	802
State net operating loss carry forward (net of federal expense)	**66**	64
Valuation allowance	**(55)**	(55)
Total deferred income tax assets	**2,116**	2,368
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,889)**	(1,665)
Deferred fuel recovery	**(74)**	(186)
Income taxes recoverable through future rates	**(782)**	(959)
Other	**(264)**	(141)
Total deferred income tax liabilities	**(3,009)**	(2,951)
Total net deferred income tax liabilities	**$(893)**	$(583)

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

(in millions)	2009	2008
Current deferred income tax assets, included in prepayments and other current assets	**$168**	$96
Noncurrent deferred income tax assets, included in other assets and deferred debits	**37**	32
Current deferred income tax liabilities, included in other current liabilities	**–**	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,098)**	(710)
Total net deferred income tax liabilities	**$(893)**	$(583)

At December 31, 2009, the federal income tax credit carry forward includes $712 million of alternative minimum tax credits that do not expire.

At December 31, 2009, we had gross state net operating loss carry forwards of $1.6 billion that will expire during the period 2010 through 2029.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of less than $1 million in our valuation allowances during 2009.

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:

	2009	2008	2007
Effective income tax rate	**32.1%**	33.7%	32.3%
State income taxes, net of federal benefit	**(3.7)**	(3.8)	(2.8)
Investment tax credit amortization	**0.8**	1.0	1.1
Employee stock ownership plan dividends	**1.0**	1.0	1.1
Domestic manufacturing deduction	**0.8**	0.3	1.0
AFUDC equity	**2.2**	2.5	0.7
Other differences, net	**1.8**	0.3	1.6
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)	**2009**	2008	2007
Current – federal	**$227**	$38	$285
– state	**41**	12	36
Deferred – federal	**114**	305	13
– state	**25**	49	11
Investment tax credit	**(10)**	(12)	(12)
State net operating loss carry forward	**–**	(6)	1
Beginning-of-the-year valuation allowance change	**–**	9	–
Total income tax expense	**$397**	$395	$334

We previously recorded a deferred income tax asset for a state net operating loss carry forward upon the sale of PVI's nonregulated generation facilities and energy marketing and trading operations. During 2008, we recorded an additional deferred income tax asset of $6 million related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. During 2008 we also evaluated this state net operating loss carry forward and recorded a partial valuation allowance of $9 million.

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

- Taxes related to discontinued operations recorded net of tax for 2009, 2008 and 2007, which are presented separately in Notes 3A through 3E.
- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, 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. No net current tax benefit was recorded in common stock during 2009 and 2008.
- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

At December 31, 2009, 2008 and 2007, our liability for unrecognized tax benefits was $160 million, $104 million and $93 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $9 million, $8 million and $10 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	2009	2008	2007
Unrecognized tax benefits at beginning of period	**$104**	$93	$126
Gross amounts of increases as a result of tax positions taken in a prior period	**11**	17	32
Gross amounts of decreases as a result of tax positions taken in a prior period	**(3)**	(11)	(41)
Gross amounts of increases as a result of tax positions taken in the current period	**52**	8	22
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(2)	(32)
Amounts of net increases (decreases) relating to settlements with taxing authorities	**–**	1	(14)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	(2)	–
Unrecognized tax benefits at end of period	**$160**	$104	$93

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our open federal tax years are from 2004 forward, and our open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on our results of operations.

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 2009, 2008 and 2007, the net interest expense related to unrecognized tax benefits was $9 million, $4 million and $1 million, respectively, of which a respective $5 million, $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2009 and 2007, there were no penalties related to unrecognized tax benefits. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. At December 31, 2009 and 2008, we had accrued $36 million and $27 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

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

(in millions)	**2009**	2008
Deferred income tax assets		
ARO liability	**$111**	$244
Derivative instruments	**37**	64
Income taxes refundable through future rates	**106**	10
Pension and other postretirement benefits	**254**	262
Other	**149**	108
Total deferred income tax assets	**657**	688
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,307)**	(1,162)
Deferred fuel recovery	**(60)**	(132)
Income taxes recoverable through future rates	**(377)**	(451)
Investments	**(71)**	(8)
Other	**(8)**	(12)
Total deferred income tax liabilities	**(1,823)**	(1,765)
Total net deferred income tax liabilities	**$(1,166)**	$(1,077)

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

(in millions)	**2009**	2008
Current deferred income tax assets, included in prepayments and other current assets	**$42**	$–
Current deferred income tax liabilities, included in other current liabilities	**–**	(5)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,208)**	(1,072)
Total net deferred income tax liabilities	**$(1,166)**	$(1,077)

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

	2009	2008	2007
Effective income tax rate	**35.0%**	35.8%	37.1%
State income taxes, net of federal benefit	**(2.8)**	(2.7)	(2.3)
Investment tax credit amortization	**0.7**	0.7	0.7
Domestic manufacturing deduction	**0.9**	0.5	1.1
Other differences, net	**1.2**	0.7	(1.6)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2009**	2008	2007
Current – federal	**$192**	$87	$235
– state	**21**	7	19
Deferred – federal	**57**	181	34
– state	**13**	29	13
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense	**$277**	$298	$295

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, 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. No net current tax benefit was recorded in common stock during 2009 and 2008.
- Taxes of $6 million that reduced retained earnings, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $38 million and $74 million at December 31, 2009 and 2008, respectively.

At December 31, 2009, 2008 and 2007, PEC's liability for unrecognized tax benefits was $59 million, $38 million and $41 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $5 million, $5 million and $9 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$38**	$41	$43
Gross amounts of increases as a result of tax positions taken in a prior period	**6**	5	3
Gross amounts of decreases as a result of tax positions taken in a prior period	**(2)**	(10)	(15)
Gross amounts of increases as a result of tax positions taken in the current period	**17**	4	22
Gross amounts of decreases as a result of tax positions taken in the current period	**–**	(1)	(5)
Amounts of net increases (decreases) relating to settlements with taxing authorities	**–**	1	(7)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	(2)	–
Unrecognized tax benefits at end of period	**$59**	$38	$41

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. PEC's open federal tax years are from 2004 forward, and PEC's open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEC cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that PEC's unrecognized tax benefits will decrease by up to approximately $10 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on PEC's results of operations.

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 2009 the interest expense recorded related to unrecognized tax benefits was $3 million. During 2008 and 2007, the interest benefit recorded related to unrecognized tax benefits was $1 million and $4 million, respectively. During 2009, 2008 and 2007, there were no penalties recorded related to unrecognized tax benefits. At December 31, 2009 and 2008, PEC had accrued $10 million and $7 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

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

(in millions)	2009	2008
Deferred income tax assets		
Derivative instruments	**$125**	$222
Income taxes refundable through future rates	**73**	54
Pension and other postretirement benefits	**163**	192
Reserve for storm damage	**52**	54
Unbilled revenue	**48**	43
Other	**89**	101
Total deferred income tax assets	**550**	666
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(568)**	(490)
Deferred fuel recovery	**(14)**	(54)
Deferred nuclear cost recovery	**(107)**	(73)
Income taxes recoverable through future rates	**(406)**	(508)
Investments	**(44)**	(3)
Other	**(26)**	(36)
Total deferred income tax liabilities	**(1,165)**	(1,164)
Total net deferred income tax liabilities	**$(615)**	$(498)

The above amounts were classified on the Balance Sheets as follows:

(in millions)	2009	2008
Current deferred income tax assets, included in deferred income taxes	**$115**	$74
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(730)**	(572)
Total net deferred income tax liabilities	**$(615)**	$(498)

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

	2009	2008	2007
Effective income tax rate	**31.1%**	32.0%	31.2%
State income taxes, net of federal benefit	**(3.0)**	(3.1)	(3.3)
Investment tax credit amortization	**0.7**	1.1	1.3
Domestic manufacturing deduction	**0.8**	0.2	0.8
AFUDC equity	**3.4**	5.4	2.6
Other differences, net	**2.0**	(0.6)	2.4
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense for the years ended December 31 was comprised of:

(in millions)	2009	2008	2007
Current – federal	**$125**	$39	$160
– state	**20**	12	28
Deferred – federal	**57**	121	(33)
– state	**11**	15	(5)
Investment tax credit	**(4)**	(6)	(6)
Total income tax expense	**$209**	$181	$144

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, 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, 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. No net current tax benefit was recorded in common stock during 2009 and 2008.

- Taxes of less than $1 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $122 million and $47 million at December 31, 2009 and 2008, respectively.

At December 31, 2009, 2008 and 2007, PEF's liability for unrecognized tax benefits was $98 million, $62 million and $55 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $3 million, $2 million and $3 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$62**	$55	$72
Gross amounts of increases as a result of tax positions taken in a prior period	**5**	6	23
Gross amounts of decreases as a result of tax positions taken in a prior period	**(1)**	(1)	(4)
Gross amounts of increases as a result of tax positions taken in the current period	**35**	3	2
Gross amounts of decreases as a result of tax positions taken in the current period	**(3)**	(1)	(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 end of period	**$98**	$62	$55

We file consolidated federal and state income tax returns that include PEF. PEF's open federal tax years are from 2004 forward and PEF's open state tax years are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. PEF cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that PEF's unrecognized tax benefits will decrease by up to approximately $50 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on PEF's results of operations.

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 or less, with the amortization included in interest charges on the Statements of Income. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense on the Statement of Income. Penalties are included in other, net on the Statements of Income. During 2009, 2008 and 2007, interest expense recorded as a regulatory asset was $5 million, $1 million and $15 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. At December 31, 2009 and 2008, PEF had accrued $24 million and $19 million, respectively, for interest and penalties, which are included in interest accrued and other assets and deferred debits on the Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, 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 coal-based solid synthetic fuels limited liability companies, of which three were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 3A). 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, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively.

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuels facilities (See Note 3E). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2009 and 2008 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2009 and 2008.

16. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

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. 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 tables below provide the components of the net periodic benefit cost for 2009, 2008 and 2007. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$42**	$46	$46	**$7**	$8	$7
Interest cost	**138**	128	123	**31**	34	32
Expected return on plan assets	**(133)**	(170)	(155)	**(4)**	(6)	(6)
Amortization of actuarial loss[(a)]	**54**	8	15	**1**	1	2
Other amortization, net[(a)]	**6**	2	2	**5**	5	5
Net periodic cost before deferral[(b)]	**$107**	$14	$31	**$40**	$42	$40

(a) Adjusted to reflect PEF's rate treatment (See Note 16B).

(b) In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (see Note 7C).

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$18**	$23	$23	**$5**	$5	$5
Interest cost	**64**	58	56	**16**	17	15
Expected return on plan assets	**(67)**	(66)	(60)	**(2)**	(4)	(4)
Amortization of actuarial loss	**11**	6	12	**–**	–	–
Other amortization, net	**6**	2	2	**1**	1	1
Net periodic cost	**$32**	$23	$33	**$20**	$19	$17

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$19**	$17	$16	**$2**	$2	$2
Interest cost	**56**	53	52	**13**	14	14
Expected return on plan assets	**(56)**	(90)	(84)	**(1)**	(1)	(1)
Amortization of actuarial loss	**38**	1	1	**–**	1	2
Other amortization, net	**–**	(1)	(1)	**3**	3	3
Net periodic cost (benefit) before deferral[(a)]	**$57**	$(20)	$(16)	**$17**	$19	$20

(a) In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (see Note 7C)

The tables below provide a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income, for 2009, 2008 and 2007. The tables also include comparable items that affected regulatory assets of PEC and PEF. For PEC and PEF, amounts that would otherwise be recorded in other comprehensive income are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process.

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$(1)**	$(64)	$24	**$4**	$(8)	$16
Other, net	**–**	(6)	(1)	**–**	–	–
Reclassification adjustments						
Net actuarial loss	**5**	1	2	**1**	–	–
Other, net		1	1	**1**	–	–
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	**10**	(735)	66	**64**	(73)	82
Other, net	**(3)**	(36)	(8)	**–**	–	–
Amortized to income[(a)]						
Net actuarial loss	**49**	7	13	**–**	1	2
Other, net	**6**	1	1	**4**	5	4

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

PEC

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**$(14)**	$(308)	$26	**$38**	$(66)	$82
Other, net	**(2)**	(31)	(6)	**–**	–	–
Amortized to net income						
Net actuarial loss	**11**	6	12	**–**	–	–
Other, net	**6**	2	2	**1**	1	1

PEF

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	**$24**	$(427)	$40	**$26**	$(6)	$–
Other, net	**(1)**	(5)	(1)	**–**	–	–
Amortized to net income[(a)]						
Net actuarial loss	**38**	1	1	**–**	1	2
Other, net	**–**	(1)	(1)	**3**	3	3

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

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

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.30%**	6.20%	5.95%	**6.20%**	6.20%	5.95%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	4.25%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	**8.75%**	9.00%	9.00%	**6.80%**	8.10%	7.70%

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 5.00% for PEF for all years presented and for PEC was 8.75%, 9.00% and 9.00% for 2009, 2008 and 2007, respectively.

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans' target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2009, primarily due to the uncertainties resulting from the severe capital market deterioration in 2008. See the "Assets of Benefit Plans" section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP 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, 2009 and 2008 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$2,234**	$2,142	**$608**	$541
Service cost	**42**	46	**7**	8
Interest cost	**138**	128	**31**	34
Settlements	**(9)**	–	–	–
Benefit payments	**(124)**	(127)	**(40)**	(35)
Plan amendment	**3**	42	–	–
Actuarial loss (gain)	**138**	3	**(63)**	60
Obligation at December 31	**2,422**	2,234	**543**	608
Fair value of plan assets at December 31	**1,673**	1,285	**55**	52
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.422 billion and $2.234 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $2.378 billion and $2.196 billion at December 31, 2009 and 2008, respectively, and plan assets of $1.673 billion and $1.285 billion at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**(9)**	(10)	**$–**	$(1)
Noncurrent liabilities	**(740)**	(939)	**(488)**	(555)
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

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)	**2009**	2008	**2009**	2008
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$83**	$87	**$(5)**	$–
Other, net	**10**	11	**–**	–
Recognized in regulatory assets, net				
Net actuarial loss	**806**	865	**32**	97
Other, net	**59**	62	**14**	18
Total not yet recognized as a component of net periodic cost[a]	**$958**	$1,025	**$41**	$115

[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 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$50	$1
Amortization of other, net[a]	6	5

[a] Adjusted to reflect PEF's rate treatment (See Note 16B).

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$1,025**	$980	**$312**	$257
Service cost	**18**	23	**5**	5
Interest cost	**64**	58	**16**	17
Plan amendment	**2**	31	**–**	–
Benefit payments	**(50)**	(55)	**(17)**	(15)
Actuarial loss (gain)	**61**	(12)	**(34)**	48
Obligation at December 31	**1,120**	1,025	**282**	312
Fair value of plan assets at December 31	**749**	521	**21**	22
Funded status	**$(371)**	$(504)	**$(261)**	$(290)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.120 billion and $1.025 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $1.116 billion and $1.021 billion at December 31, 2009 and 2008, respectively, and plan assets of $749 million and $521 million at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**$(2)**	$(2)	**$ –**	$ –
Noncurrent liabilities	**(369)**	(502)	**(261)**	(290)
Funded status	**$(371)**	$(504)	**$(261)**	$(290)

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)	**2009**	2008	**2009**	2008
Recognized in regulatory assets				
Net actuarial loss	**$410**	$407	**$16**	$54
Other, net	**54**	57	**3**	4
Total not yet recognized as a component of net periodic cost	**$464**	$464	**$19**	$58

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$16	$–
Amortization of other, net	6	1

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$914**	$881	**$248**	$245
Service cost	**19**	17	**2**	2
Interest cost	**56**	53	**13**	14
Plan amendment	**–**	5	**–**	–
Benefit payments	**(58)**	(58)	**(20)**	(18)
Actuarial loss (gain)	**61**	16	**(24)**	5
Obligation at December 31	**992**	914	**219**	248
Fair value of plan assets at December 31	**794**	650	**32**	27
Funded status	**$(198)**	$(264)	**$(187)**	$(221)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $992 million and $914 million at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $957 million and $884 million at December 31, 2009 and 2008, respectively, and plan assets of $794 million and $650 million at December 31, 2009 and 2008, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**$(3)**	$(3)	**$–**	$–
Noncurrent liabilities	**(195)**	(261)	**(187)**	(221)
Funded status	**$(198)**	$(264)	**$(187)**	$(221)

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)	**2009**	2008	**2009**	2008
Recognized in regulatory assets, net				
Net actuarial loss	**$396**	$458	**$16**	$43
Other, net	**5**	5	**11**	14
Total not yet recognized as a component of net periodic cost	**$401**	$463	**$27**	$57

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	$30	$1
Amortization of other, net	–	4

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.30%	**6.05%**	6.20%
Rate of increase in future compensation				
Bargaining	**4.50%**	4.25%	–	–
Supplementary plans	**5.25%**	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	**8.50%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	**8.50%**	9.00%
Ultimate medical cost trend rate	–	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	–	–	**2016**	2016

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. Therefore, we 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	26	14	11
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(1)	(1)	–
Effect on postretirement benefit obligation	(21)	(11)	(9)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions for 2009 include contributions directly to pension plan assets of $222 million, $163 million and $58 million, respectively, and for 2008 include contributions directly to pension plan assets of $33 million, $24 million and less than $1 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, 25 percent for PEC and 15 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2009, the subsidies totaled $3 million for us, $1 million for PEC and $1 million for PEF. In 2008, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

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

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$1,285**	$1,996	**$52**	$75
Actual return on plan assets	**279**	(627)	**9**	(16)
Benefit payments, including settlements	**(133)**	(127)	**(40)**	(35)
Employer contributions	**242**	43	**34**	28
Fair value of plan assets at December 31	**$1,673**	$1,285	**$55**	$52

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$521**	$805	**$22**	$44
Actual return on plan assets	**113**	(255)	**5**	(14)
Benefit payments	**(50)**	(55)	**(17)**	(15)
Employer contributions	**165**	26	**11**	7
Fair value of plan assets at December 31	**$749**	$521	**$21**	$22

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$650**	$1,026	**$27**	$26
Actual return on plan assets	**141**	(321)	**3**	–
Benefit payments	**(58)**	(58)	**(20)**	(18)
Employer contributions	**61**	3	**22**	19
Fair value of plan assets at December 31	**$794**	$650	**$32**	$27

The Progress Registrants' primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rolling 10-year annual return of 6 percent over the rate of inflation. The target pension asset allocations are 40 percent domestic equity, 20 percent international equity, 10 percent domestic fixed income, 15 percent global fixed income, 10 percent private equity and timber and 5 percent hedge funds. 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. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth based investment strategies. Domestic fixed income primarily includes domestic investment grade fixed income investments. Global fixed income includes domestic and foreign fixed income investments. A substantial portion of OPEB plan assets are managed with pension assets. The remaining OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

PROGRESS ENERGY

The following table sets forth by level within the fair value hierarchy of our pension and other postretirement plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$1	$96	$–	$97
Domestic equity securities	263	1	–	264
Private equity securities	–	–	122	122
Corporate bonds	–	67	–	67
U.S. state and municipal debt	–	4	–	4
U.S. and foreign government debt	25	95	–	120
Mortgage backed securities	–	22	–	22
Commingled funds	–	888	–	888
Hedge funds	–	47	2	49
Timber investments	–	–	14	14
Credit default swaps	–	20	–	20
Interest rate swaps and other investments	–	36	–	36
Total assets	$289	$1,276	$138	$1,703
Liabilities				
Foreign currency contracts	(5)	–	–	(5)
Credit default swaps	–	(20)	–	(20)
Interest rate swaps and other investments	–	(5)	–	(5)
Total liabilities	(5)	(25)	–	(30)
Fair value of plan assets	$284	$1,251	$138	$1,673

	Other Postretirement Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. state and municipal debt	–	32	–	32
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	13	–	13
Hedge funds	–	1	–	1
Interest rate swaps and other investments	–	1	–	1
Fair value of plan assets	$4	$51	$–	$55

The following table sets forth a reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$111	$2	$18	$131
Net realized and unrealized (losses)[a]	(10)	–	(4)	(14)
Purchases, sales and distributions, net	21	–	–	21
Balance at December 31	$122	$2	$14	$138

[a] Substantially all amounts relate to investments held at December 31, 2009.

PEC

The following table sets forth by level within the fair value hierarchy of PEC's pension and other postretirement plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$–	$43	$–	$43
Domestic equity securities	118	–	–	118
Private equity securities	–	–	55	55
Corporate bonds	–	30	–	30
U.S. state and municipal debt	–	2	–	2
U.S. and foreign government debt	11	43	–	54
Mortgage backed securities	–	10	–	10
Commingled funds	–	398	–	398
Hedge funds	–	21	1	22
Timber investments	–	–	6	6
Credit default swaps	–	9	–	9
Interest rate swaps and other investments	–	15	–	15
Total assets	$129	$571	$62	$762
Liabilities				
Foreign currency contracts	(2)	–	–	(2)
Credit default swaps	–	(9)	–	(9)
Interest rate swaps and other investments	–	(2)	–	(2)
Total liabilities	(2)	(11)	–	(13)
Fair value of plan assets	$127	$560	$62	$749

	Other Postretirement Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	12	–	12
Hedge funds	–	1	–	1
Fair value of plan assets	$4	$17	$–	$21

The following table sets forth a reconciliation of changes in the fair value of PEC's pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$49	$1	$8	$58
Net realized and unrealized (losses)[a]	(4)	–	(2)	(6)
Purchases, sales and distributions, net	10	–	–	10
Balance at December 31	$55	$1	$6	$62

[a] Substantially all amounts relate to investments held at December 31, 2009.

PEF

The following table sets forth by level within the fair value hierarchy of PEF's pension plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$–	$46	$–	$46
Domestic equity securities	125	–	–	125
Private equity securities	–	–	58	58
Corporate bonds	–	32	–	32
U.S. state and municipal debt	–	2	–	2
U.S. and foreign government debt	12	45	–	57
Mortgage backed securities	–	10	–	10
Commingled funds	–	421	–	421
Hedge funds	–	22	1	23
Timber investments	–	–	7	7
Credit default swaps	–	9	–	9
Interest rate swaps and other investments	–	17	–	17
Total assets	$137	$604	$66	$807
Liabilities				
Foreign currency contracts	(2)	–	–	(2)
Credit default swaps	–	(9)	–	(9)
Interest rate swaps and other investments	–	(2)	–	(2)
Total liabilities	(2)	(11)	–	(13)
Fair value of plan assets	$135	$593	$66	$794

PEF's other postretirement benefit plan assets had a fair value of $32 million which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy as of December 31, 2009.

The following table sets forth a reconciliation of changes in the fair value of PEF's pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$53	$1	$9	$63
Net realized and unrealized (losses)[a]	(5)	–	(2)	(7)
Purchases, sales and distributions, net	10	–	–	10
Balance at December 31	$58	$1	$7	$66

[a] Substantially all amounts relate to investments held at December 31, 2009.

For Progress Energy, PEC and PEF, the determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments

Investments in commingled funds are not publically traded, but the underlying assets held in these funds are traded in active markets and the prices for these assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2010, we expect to make $120 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $158, $161, $167, $170, $178 and $961, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $37, $40, $42, $45, $46 and $251, 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $4, $4, $5, $5, $6 and $40, respectively.

In 2010, PEC expects to make $85 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $80, $81, $84, $84, $90 and $462, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $17, $18, $20, $22, $23 and $133, 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $2, $2, $2, $3, $3 and $21, respectively.

In 2010, PEF expects to make $35 million in 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $59, $60, $62, $64, $66 and $376, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $18, $19, $19, $19, $20 and $98, 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $2, $2, $2, $2, $3 and $15, 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 and financial reviews using a combination of financial analysis and 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.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary PVI sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. 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 was included in discontinued operations on the Consolidated Statements of Income.

In 2007, we entered into derivative contracts to hedge economically a portion of our synthetic fuels cash flow exposure to the risk of rising oil prices. 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 in January 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed in Note 3E, we disposed of our 100 percent ownership interest in Ceredo in March 2007. Progress Energy is the primary beneficiary of, and continues to consolidate, Ceredo in accordance with GAAP for variable interest entities, but we have recorded a 100 percent noncontrolling interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. 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 noncontrolling interest for the portion of the gain subsequent to the disposal of Ceredo.

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.

The Utilities have derivative instruments through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2010 and 2011. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have held cash collateral from PEC in support of these instruments. PEC had a $7 million and an $18 million cash collateral asset included in prepayments and other current assets on the PEC Consolidated Balance Sheet at December 31, 2009 and 2008, respectively. At December 31, 2009, PEC had 50.3 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted PEF's cash collateral asset included in derivative collateral posted on the PEF Balance Sheet, which was $139 million at December 31, 2009, compared to $335 million at December 31, 2008. At December 31, 2009, PEF had 182.4 million MMBtu notional of natural gas and 56.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. At December 31, 2009, we had 0.4 million gallons notional of gasoline and 0.5 million gallons notional of heating oil related to outstanding commodity derivative swaps at each of PEC and PEF that were entered into to hedge forecasted gasoline and diesel purchases. Realized gains and losses are recorded net as part of fleet vehicle fuel costs. At December 31, 2009 and 2008, 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 2009, 2008 and 2007.

At December 31, 2009 and 2008, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

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. Our cash flow hedging strategies are primarily accomplished through the use of forward starting swaps and our fair value hedging strategies are primarily accomplished through the use of fixed-to-floating swaps. 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

At December 31, 2009, all open forward starting swaps will reach their mandatory termination dates within three years. At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses, including $27 million of after-tax losses at PEC and $3 million of after-tax gains at PEF, recorded in accumulated other comprehensive income related to interest cash flow hedges. It is expected that in the next 12 months losses of $7 million and $4 million, net of tax, will be reclassified to interest expense at Progress Energy and PEC, respectively. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of the timing of debt issuances at the Parent and the Utilities and changes in market value of currently open forward starting swaps.

At December 31, 2008, including amounts related to terminated hedges, we had $56 million of after-tax losses, including $35 million of after-tax losses at PEC recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2007, including amounts related to terminated hedges, we had $24 million of after-tax losses, including $12 million of after-tax losses at PEC and $8 million of after-tax losses at PEF, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million at PEC and $75 million at PEF. At December 31, 2008, Progress Energy had $450 million notional of open forward starting swaps, including $250 million at PEC. At December 31, 2008, PEF had no open forward starting swaps. During January 2010, Progress Energy entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, including $75 million notional at PEF.

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, 2009 and 2008, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with each of the major credit rating agencies. Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from each of the major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

The aggregate fair value of all derivative instruments at Progress Energy with credit risk-related contingent features that were in a liability position at December 31, 2009, was $405 million, for which Progress Energy had posted collateral of $146 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, Progress Energy would have been required to post an additional $260 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEC with credit risk-related contingent features that were in a liability position at December 31, 2009, was $90 million, for which PEC had posted collateral of $7 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, PEC would have been required to post an additional $83 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEF with credit risk-related contingent features that were in a liability position at December 31, 2009, was $315 million, for which PEF had posted collateral of $139 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered on December 31, 2009, PEF would have been required to post an additional $177 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

Progress Energy

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location	December 31, 2009		December 31, 2008	
(in millions)	Asset	Liability	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		$–		$(2)
Interest rate derivatives				
Prepayments and other current assets	$5		$–	
Other assets and deferred debits	14		–	
Derivative liabilities, current				(65)
Total derivatives designated as hedging instruments	19	–	–	(67)
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	11		9	
Other assets and deferred debits	9		1	
Derivative liabilities, current		(189)		(425)
Derivative liabilities, long-term		(236)		(263)
CVOs[b]				
Other liabilities and deferred credits		(15)		(34)
Fair value of derivatives not designated as hedging instruments	20	(440)	10	(722)
Fair value loss transition adjustment[c]				
Derivative liabilities, current		(1)		(1)
Derivative liabilities, long-term		(4)		(6)
Total derivatives not designated as hedging instruments	20	(445)	10	(729)
Total derivatives	$39	$(445)	$10	$(796)

[a] Substantially all of these contracts receive regulatory treatment

[b] The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000 (See Note 15).

[c] In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008.

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a] 2009	2008	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a] 2009	2008	Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b] 2009	2008
Commodity cash flow derivatives	**$1**	$(2)		**$–**	$–		**$–**	$–
Interest rate derivatives[c]	**15**	(35)	Interest charges	**(6)**	(3)	Interest charges	**(3)**	1

[a] Effective portion.
[b] Related to ineffective portion and amount excluded from effectiveness testing.
[c] Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)[a] 2009	2008	Unrealized Gain or (Loss)[b] 2009	2008
Commodity derivatives	**$(659)**	$174	**$(387)**	$(653)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

Instrument (in millions)	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives 2009	2008
Commodity derivatives	Other, net	**$1**	$(3)
Fair value loss transition adjustment	Other, net	**2**	3
CVOs	Other, net	**19**	–
Total		**$22**	$–

PEC

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location (in millions)	December 31, 2009 Asset	December 31, 2009 Liability	December 31, 2008 Asset	December 31, 2008 Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		$–		$(1)
Interest rate derivatives				
Other assets and deferred debits	$8		$–	
Derivative liabilities, current		–		(35)
Total derivatives designated as hedging instruments	8	–	–	(36)
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Derivative liabilities, current		(28)		(45)
Other liabilities and deferred credits		(62)		(54)
Fair value of derivatives not designated as hedging instruments		(90)		(99)
Fair value loss transition adjustment[b]				
Derivative liabilities, current		(1)		(1)
Other liabilities and deferred credits		(4)		(6)
Total derivatives not designated as hedging instruments		(95)		(106)
Total derivatives	$8	$(95)	$–	$(142)

[a] Substantially all of these contracts receive regulatory treatment.

[b] In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a] 2009	2008	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a] 2009	2008	Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b] 2009	2008
Commodity cash flow derivatives	$–	$(1)		$–	$–		$–	$–
Interest rate derivatives[c]	5	(25)	Interest charges	(3)	(1)	Interest charges	(2)	–

[a] Effective portion.

[b] Related to ineffective portion and amount excluded from effectiveness testing.

[c] Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments				
Instrument	Realized Gain or (Loss)[a]		Unrealized Gain or (Loss)[b]	
(in millions)	**2009**	2008	**2009**	2008
Commodity derivatives	**$(76)**	$2	**$(68)**	$(110)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

Instrument	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
(in millions)		**2009**	2008
Commodity derivatives	Other, net	**$1**	$(3)
~~Fair value loss transition adjustment~~	~~Other, net~~	~~2~~	~~3~~
Total		$3	$–

PEF

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument / Balance sheet location	**December 31, 2009**		December 31, 2008	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Prepayments and other current assets	$5		$–	
Total derivatives designated as hedging instruments	5		–	
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	11		9	
Other assets and deferred debits	9		1	
Derivative liabilities, current		$(161)		$(380)
Derivative liabilities, long-term		(174)		(209)
Total derivatives not designated as hedging instruments	20	(335)	10	(589)
Total derivatives	$25	$(335)	$10	$(589)

[a] Substantially all of these contracts receive regulatory treatment.

The following tables present the effect of derivative instruments on the Statements of Comprehensive Income and the Statements of Income for the years ended December 31, 2009 and 2008.

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]		Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]	
(in millions)	**2009**	2008		**2009**	2008		**2009**	2008
Commodity cash flow derivatives	**$1**	$(1)		**$–**	$–		**$–**	$–
Interest rate derivatives[c]	**3**	8	Interest charges	**–**	–	Interest charges	**–**	1

[a] Effective portion.
[b] Related to ineffective portion and amount excluded from effectiveness testing.
[c] Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)[a]		Unrealized Gain or (Loss)[b]	
(in millions)	**2009**	2008	**2009**	2008
Commodity derivatives	**$(583)**	$172	**$(319)**	$(543)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Statements of Income.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

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 may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2009, the Parent had issued $391 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). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935. The repeal of the Public Utility Holding Company Act of 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 2009, 2008 and 2007 to PEC amounted to $170 million, $194 million and $182 million, respectively, and services provided to PEF were $147 million, $160 million and $174 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2009, 2008 and 2007 amounted to $36 million, $44 million and $54 million, respectively. Services provided by PEF to PEC during 2009, 2008 and 2007 amounted to $12 million, $12 million and $10 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 0.73%, 3.29% and 5.49% for the years ended December 31, 2009, 2008 and 2007, 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.

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 segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. 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 thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

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
At and for the year ended December 31, 2009					
Revenues					
Unaffiliated	$4,627	$5,249	$9	$–	$9,885
Intersegment	–	2	234	(236)	–
Total revenues	4,627	5,251	243	(236)	9,885
Depreciation, amortization and accretion	470	502	14	–	986
Interest income	5	4	38	(33)	14
Total interest charges, net	195	231	286	(33)	679
Income tax expense (benefit)[(a)]	294	209	(87)	–	416
Ongoing Earnings (loss)	540	460	(154)	–	846
Total assets	13,502	13,100	20,538	(15,904)	31,236
Capital and investment expenditures	962	1,532	21	(12)	2,503

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
At and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$ –	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Ongoing Earnings (loss)	531	383	(138)	–	776
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
At 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, amortization and accretion	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
Ongoing Earnings (loss)	498	315	(118)	–	695
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204

[a] Income tax expense (benefit) for 2009 excludes tax impact of $17 million benefit at PEC and $1 million benefit at Corporate and Other for Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. A reconciliation of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended 2009, 2008 and 2007, respectively, is as follows:

(in millions)	**2009**	2008	2007
Ongoing Earnings	**$846**	$776	$695
CVO mark-to-market	**19**	–	(2)
Impairment, net of tax benefit of $1	**(2)**	–	–
Plant retirement charge, net of tax benefit of $11	**(17)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $6 (See Note 24)	**(10)**	–	–
Valuation allowance and related net operating loss carry forward	–	(3)	–
Continuing income attributable to noncontrolling interests, net of tax	**4**	5	9
Income from continuing operations	**840**	778	702
Discontinued operations, net of tax	**(79)**	58	(206)
Net income attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Net income attributable to controlling interests	**$757**	$830	$504

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income; AFUDC equity, which represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets; and other, net. The components of other, net as shown on the accompanying Statements of Income are presented 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.

Progress Energy

(in millions)	2009	2008	2007
Nonregulated energy and delivery services income, net	**$17**	$17	$12
Fair value loss transition adjustment amortization (Note 17D)	**2**	3	4
CVO unrealized gain (loss), net (Note 15)	**19**	–	(2)
Donations	**(20)**	(25)	(22)
Other, net	**(12)**	(12)	1
Other, net	**$6**	$(17)	$(7)

PEC

(in millions)	2009	2008	2007
Nonregulated energy and delivery services income, net	**$6**	$11	$6
Fair value loss transition adjustment amortization (Note 17D)	**2**	3	4
Donations	**(10)**	(14)	(9)
Other, net	**(16)**	4	5
Other, net	**$(18)**	$4	$6

PEF

(in millions)	2009	2008	2007
Nonregulated energy and delivery services income, net	**$11**	$8	$8
Donations	**(10)**	(11)	(8)
Other, net	**4**	(7)	(2)
Other, net	**$5**	$(10)	$(2)

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 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 potential and pending claims cannot be predicted. 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~~ current liabilities and other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	**2009**	2008
PEC		
MGP and other sites[(a)]	**$13**	$16
PEF		
Remediation of distribution and substation transformers	**20**	22
MGP and other sites	**9**	15
Total PEF environmental remediation accruals[(b)]	**29**	37
Total Progress Energy environmental remediation accruals	**$42**	$53

(a) Expected to be paid out over one to five years.
(b) Expected to be paid out over one to 15 years.

PROGRESS ENERGY

Including PEC's Ward Transformer site located in Raleigh, N.C. (Ward), PEF's distribution and substation transformers sites, and the Utilities' MGP sites discussed below, for the year ended December 31, 2009, we accrued approximately $16 million and spent approximately $27 million. For the year ended December 31, 2008, we accrued approximately $25 million and spent approximately $36 million. For the year ended December 31, 2007, we accrued approximately $8 million and spent approximately $27 million.

In addition to these sites, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

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 accruals for PEF's MGP and other sites 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 maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2009 and 2008, PEC's recorded liability for the site was approximately $4 million and $7 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed an initial civil action against a number of PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. On March 13, 2009, a subsequent action was filed against additional PRPs, and on April 30, 2009, suit was filed against the remaining approximately 160 PRPs. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. With respect to the defendants that do not settle, the federal district court in which this matter is pending requires that alternative dispute resolution be pursued early in civil litigation but it is unclear what process the court will require. The outcome of these matters cannot be predicted.

On September 30, 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for the operable unit for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On January 19, 2009, PEC and several of the other participating PRPs at the Ward site submitted a letter containing a good faith response to the EPA's special notice letter. Another group of PRPs separately submitted a good faith response, which the EPA advised would be used to negotiate implementation of the required actions. The other PRPs' good faith response was subsequently withdrawn. Discussions among representatives of certain PRPs, including PEC, and the EPA are ongoing. Although a loss is considered probable, an agreement among the PRPs for these matters has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation, if any, for Ward OU1 and Ward OU2.

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. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC. For the year ended December 31, 2009, PEF accrued approximately $13 million due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $15 million related to the remediation of transformers. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. 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. At December 31, 2009 and 2008, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

PEC

Including Ward, and MGP sites previously discussed in "Progress Energy," for the year ended December 31, 2009, PEC accrued approximately $3 million and spent approximately $6 million. For the year ended December 31, 2008, PEC accrued and spent approximately $8 million. For the year ended December 31, 2007, PEC's accruals and expenditures were not material. These amounts primarily relate to the Ward site, which is discussed under "Progress Energy" above.

PEF

Including the distribution and substation transformer sites and MGP and other sites previously discussed in "Progress Energy," for the year ended December 31, 2009, PEF accrued approximately $13 million and spent approximately $21 million, including $6 million of expenditures related to MGP and other sites. For the year ended December 31, 2008, PEF accrued approximately $17 million and spent approximately $28 million, which primarily related to distribution and substation transformer sites. For the year ended December 31, 2007, PEF accrued approximately $10 million and spent approximately $22 million, which primarily related to distribution and substation transformer sites. For the years ended December 31, 2008 and 2007, PEF's accruals and expenditures for MGP and other sites were not material.

B. AIR AND WATER QUALITY

At December 31, 2009 and 2008, we were 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 included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act, enacted in June 2002 and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2009, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $2.119 billion, including $1.054 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $1.065 billion at PEF, which related entirely to in-process CAIR projects. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, in response to petitions for rehearing filed by a number of parties, the D.C. Court of Appeals remanded the CAIR without vacating the rule for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. Because the D.C. Court of Appeals December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions or BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard consistent with the agency's original listing determination. 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 will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. Under an agreement with the FDEP, PEF will retire CR1 and CR2 as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. As discussed under "Other Matters – Nuclear," PEF expects the schedule for the commercial operation of Levy to shift later than the 2016 to 2018 timeframe by a minimum of 20 months. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. PEF has advised the FDEP of a Levy schedule shift. We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. At December 31, 2009 and 2008, PEC had approximately $13 million and $22 million, respectively, in SO_2 emission allowances and an immaterial amount of NOx emission allowances. At December 31, 2009 and 2008, PEF had approximately $7 million and $11 million, respectively, in SO_2 emission allowances and approximately $36 million and $65 million, respectively, in NOx emission allowances.

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, in 2005 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. All of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, have been placed in service and PEC estimates its remaining exposure is not material. See Note 22C for further discussion of PEC's indemnification liability. 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. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service.

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2009, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$2,647	$2,335	$1,953	$1,706	$1,405	$8,217
Purchased power	445	467	447	445	367	3,636
Construction obligations	1,820	1,725	1,453	1,524	1,313	1,543
Other purchase obligations	52	74	36	27	19	163
Total	$4,964	$4,601	$3,889	$3,702	$3,104	$13,559

PEC

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$1,354	$1,192	$1,004	$1,003	$802	$3,553
Purchased power	91	98	80	73	68	505
Construction obligations	365	184	13	15	4	–
Other purchase obligations	16	11	5	5	6	6
Total	$1,826	$1,485	$1,102	$1,096	$880	$4,064

PEF

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$1,293	$1,143	$949	$703	$603	$4,664
Purchased power	354	369	367	372	299	3,131
Construction obligations	1,455	1,541	1,440	1,509	1,309	1,543
Other purchase obligations	23	36	29	21	14	157
Total	$3,125	$3,089	$2,785	$2,605	$2,225	$9,495

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our payments under these commitments were $2.921 billion, $3.078 billion and $2.360 billion for 2009, 2008 and 2007, respectively. PEC's total payments under these commitments for its generating plants were $1.527 billion, $1.446 billion and $1.049 billion in 2009, 2008 and 2007, respectively. PEF's payments totaled $1.394 billion, $1.632 billion and $1.311 billion in 2009, 2008 and 2007, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are recovered through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units. (See discussion under Construction Obligations below.) This $334 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2010 to 2029. These purchased power contracts generally provide for capacity and energy payments.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility. One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $24 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $24 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River LLC's Broad River facility agreements amounted to $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $12 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2029. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $24 million, $55 million and $95 million in 2009, 2008 and 2007, respectively.

PEF has firm contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (12 percent of net output) of purchased power that ends in 2010. Additional contracts with Southern Company for approximately 424 MW (25 percent of net output) of purchased power annually start in 2010 and extend through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $149 million, $178 million and $161 million for 2009, 2008 and 2007, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million, $56 million, $44 million, $52 million and $52 million for 2010 through 2014, respectively, and $74 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2010 to 2025. 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 net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity and energy payments made under these contracts amounted to $435 million, $440 million and $447 million for 2009, 2008 and 2007, respectively. Minimum expected future capacity payments under these contracts are $286 million, $301 million, $313 million, $310 million and $237 million for 2010 through 2014, respectively, and $3.042 billion payable 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 2009, PEC executed a long-term coal transportation agreement by combining, amending and restating previous agreements with Norfolk Southern Railroad. This agreement will support PEC's coal supply needs through June 2020. Expected future transportation payments under this agreement are $254 million, $264 million, $260 million, $254 million and $277 million for 2010 through 2014, respectively, with approximately $1.679 billion payable thereafter. Coal transportation expenses under these agreements were approximately $283 million in 2009. PEC's state utility commissions allow fuel-related costs to be recovered through fuel cost-recovery clauses.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through August 2032. The estimated total cost to PEC associated with these agreements is approximately $1.598 billion, of which approximately $404 million will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until approximately 2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEC's fuel commitments.

In April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.065 billion. In addition to the FGT contracts, PEF has entered into additional gas supply and transportation arrangements for the period from 2010 through 2036 The total current notional cost of these additional agreements is estimated to be approximately $1.043 billion. The FGT contracts along with the additional gas supply and transportation arrangements are subject to several conditions precedent, including various federal regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEF's fuel commitments.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $818 million, $1.018 billion and $698 million for 2009, 2008 and 2007, respectively. The majority of our construction obligations relate to PEF as discussed below.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $199 million, $140 million and $208 million for 2009, 2008 and 2007, respectively.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.608 billion are included for the multi-year contract and do not assume any joint ownership. The contractual obligations presented are in accordance with the existing terms of the EPC agreement. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance resulting in a minimum 20-month in-service schedule shift for the Levy units from the original 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in construction obligations. See Note 7C for additional information about the Levy project. PEF made payments of $243 million and $117 million in 2009 and 2008, respectively, toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $376 million, $761 million and $490 million for 2009, 2008 and 2007, 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 PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $56 million, $110 million and $75 million for 2009, 2008 and 2007, respectively.

PEC has various purchase obligations including obligations for limestone supply and fleet vehicles. Total purchases under these contracts were $14 million, $18 million and $6 million for 2009, 2008 and 2007, respectively.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow Plant, emission obligations and fleet vehicles. Total payments under these contracts were $22 million, $58 million and $24 million for 2009, 2008 and 2007, respectively. Future obligations are primarily comprised of the long-term service agreements.

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 $37 million, $38 million and $40 million for 2009, 2008 and 2007, respectively. Our purchased power expense under agreements classified as operating leases was approximately $11 million, $152 million and $69 million in 2009, 2008 and 2007, respectively.

PEC's rent expense under operating leases totaled $26 million, $26 million and $23 million during 2009, 2008 and 2007, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million, $5 million and $6 million for 2009, 2008 and 2007, respectively. Purchased power expense under agreements classified as operating leases was approximately $11 million, $9 million and $10 million in 2009, 2008 and 2007, respectively.

PEF's rent expense under operating leases totaled $11 million, $11 million and $15 million during 2009, 2008 and 2007, respectively. These amounts include rent expense allocated from PESC to PEF of $3 million, $3 million and $6 million for 2009, 2008 and 2007, respectively. Purchased power expense under agreements classified as operating leases was approximately $142 million and $59 million in 2008 and 2007, respectively. PEF had no purchased power expense under operating lease agreements for 2009.

Assets recorded under capital leases, including plant related to purchased power agreements, at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Buildings	**$267**	$267	**$30**	$30	**$237**	$237
Less: Accumulated amortization	**(37)**	(28)	**(15)**	(14)	**(22)**	(14)
Total	**$230**	$239	**$15**	$16	**$215**	$223

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our and the Utilities' capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $26 million each for 2009 and 2008 and $22 million for 2007, which was primarily comprised of PEF's capital lease expense of $24 million each for 2009 and 2008 and $20 million for 2007.

At December 31, 2009, 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
2010	$28	$35	$2	$25	$26	$6
2011	28	29	2	21	26	6
2012	28	48	2	20	26	26
2013	36	78	10	42	26	34
2014	26	77	–	42	26	33
Thereafter	246	941	–	558	246	382
Minimum annual payments	392	$1,208	16	$708	376	$487
Less amount representing imputed interest	(162)		(2)		(160)	
Present value of net minimum lease payments under capital leases	$230		$14		$216	

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 2008, PEC entered into a 336-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for an initial minimum payment of approximately $18 million in 2013, with minimum annual payments escalating at a rate of 2.5 percent through 2032, for a total of approximately $460 million.

In 2009, PEC entered into a 240-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $10 million from July 2012 through September 2017, for a total of approximately $52 million.

In 2007, PEF entered into a 632-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from June 2012 through May 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 minimum 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 a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $11 million for 2010 and none thereafter. PEC's rents received are contingent upon usage and totaled $34 million for 2009 and $33 million each for 2008 and 2007. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $84 million, $81 million and $78 million for 2009, 2008 and 2007, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2010 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2009, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2009, 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. At December 31, 2009, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. 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. At December 31, 2009 and 2008, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $34 million and $61 million, respectively. These amounts included $10 million for PEC at December 31, 2008, and $7 million and $8 million, respectively, for PEF at December 31, 2009 and 2008. During the year ended December 31, 2009, our indemnification liability for certain legal matters made in connection with the sale of businesses decreased by approximately $16 million as a result of a legal verdict discussed under "Synthetic Fuels Matters" in Note 22D. 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. At December 31, 2009, all of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, had been placed in service. PEC estimates its remaining exposure under the indemnification is not material (See Note 21B). During the year ended December 31, 2009, PEC accrued approximately $2 million and spent approximately $12 million that exceeded the joint owner limit. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 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 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. 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 damage claims as they incur additional costs.

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. Oral arguments were held on May 4, 2009. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. 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. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000, (the Asset Purchase Agreement) by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was 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 the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global had requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations (See Note 3A).

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations (See Note 3A), which was net of a previously recorded indemnification liability of $16 million. In December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. On December 16, 2009, we filed notice of appeal. We cannot predict the outcome of this matter.

In a second suit filed in the Superior Court for Wake County, N.C., *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC* (the North Carolina Global Case), the Progress Affiliates seek 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. Based upon the resolution of the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the Florida Global Case 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.~~

NOTICE OF VIOLATION

On April 29, 2009, the EPA issued a notice of violation and opportunity to show cause with respect to a 16,000-gallon oil spill at one of PEC's substations in 2007. The notice of violation did not include specified sanctions sought. Subsequently, the EPA notified PEC that the agency is seeking monetary sanctions that are *de minimus* to our and PEC's results of operations or financial condition. Discussions between PEC and the EPA are ongoing. We cannot predict the outcome of this matter.

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. PEF believes the lawsuit is without merit and will defend against it. 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 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 annual 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. At December 31, 2009, 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 11B, there were no restrictions on PEC's or PEF's retained earnings

The Trust is a variable-interest entity of which we are not the primary beneficiary. 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 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 Non-guarantor Subsidiaries column includes the consolidated financial results of all non-guarantor subsidiaries, which is primarily comprised of our wholly owned subsidiary PEC. The Other column includes elimination entries for all intercompany transactions and other consolidation adjustments. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-K. 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.

Condensed Consolidating Statement of Income
Year Ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$5,259	$4,626	$–	$9,885
Affiliate revenues	–	–	235	(235)	–
Total operating revenues	–	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	–	2,072	1,680	–	3,752
Purchased power	–	682	229	–	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	–	502	484	–	986
Taxes other than on income	–	347	216	(6)	557
Other	–	13	–	–	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	–	91	33	–	124
Other, net	18	6	(22)	4	6
Total other income (expense), net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	–	(27)	(12)	–	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	–	–	(875)	–
Income (loss) from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	–	(79)
Net income (loss)	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	–	(3)	2	(3)	(4)
Net income (loss) attributable to controlling interests	$757	$407	$478	$(885)	$757

Condensed Consolidating Statement of Income
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Affiliate revenues	–	–	361	(361)	–
Total operating revenues	–	4,738	4,790	(361)	9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,346	(342)	1,820
Depreciation, amortization and accretion	–	306	533	–	839
Taxes other than on income	–	309	207	(8)	508
Other	–	1	(4)	–	(3)
Total operating expenses	3	4,057	3,774	(350)	7,484
Operating (loss) income	(3)	681	1,016	(11)	1,683
Other income (expense)					
Interest income	11	9	16	(12)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	(4)	5	(17)
Total other income (expense), net	11	86	39	(7)	129
Interest charges					
Interest charges	201	263	227	(12)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	215	(12)	639
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(193)	532	840	(6)	1,173
Income tax (benefit) expense	(85)	172	306	2	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Income (loss) from continuing operations	833	360	534	(949)	778
Discontinued operations, net of tax	(3)	61	–	–	58
Net income (loss)	830	421	534	(949)	836
Net income attributable to noncontrolling interests, net of tax	–	(6)	–	–	(6)
Net income (loss) attributable to controlling interests	$830	$415	$534	$(949)	$830

Condensed Consolidating Statement of Income
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Affiliate revenues	–	–	391	(391)	–
Total operating revenues	–	4,768	4,776	(391)	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	1,369	(371)	1,842
Depreciation, amortization and accretion	–	369	536	–	905
Taxes other than on income	–	309	202	(10)	501
Other	–	20	98	(88)	30
Total operating expenses	10	4,178	3,888	(469)	7,607
Operating (loss) income	(10)	590	888	78	1,546
Other income (expense)					
Interest income	27	8	24	(25)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	(9)	4	(7)
Total other income (expense), net	27	47	25	(21)	78
Interest charges					
Interest charges	203	210	219	(27)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	214	(27)	588
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(186)	439	699	84	1,036
Income tax (benefit) expense	(79)	117	297	(1)	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Income (loss) from continuing operations	489	322	402	(511)	702
Discontinued operations, net of tax	15	13	(137)	(97)	(206)
Net income (loss)	504	335	265	(608)	496
Net loss attributable to noncontrolling interests, net of tax	–	8	–	–	8
Net income (loss) attributable to controlling interests	$504	$343	$265	$(608)	$504

Condensed Consolidating Balance Sheet
December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$9,733	$9,886	$114	$19,733
Current assets					
Cash and cash equivalents	606	72	47	–	725
Notes receivable from affiliated companies	30	46	303	(379)	–
Regulatory assets	–	54	88	–	142
Derivative collateral posted	–	139	7	–	146
Income taxes receivable	5	97	50	(7)	145
Prepayments and other current assets	14	1,158	1,377	(176)	2,373
Total current assets	655	1,566	1,872	(562)	3,531
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,348	–	–	(13,348)	–
Regulatory assets	–	1,307	873	(1)	2,179
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	496	871	–	1,367
Other assets and deferred debits	166	202	923	(520)	771
Total deferred debits and other assets	13,514	2,005	2,667	(10,214)	7,972
Total assets	$14,169	$13,304	$14,425	$(10,662)	$31,236
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$9,449	$4,590	$5,085	$(9,675)	$9,449
Noncontrolling interests	–	3	3	–	6
Total equity	9,449	4,593	5,088	(9,675)	9,455
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	4,193	3,883	3,703	–	11,779
Total capitalization	13,642	8,819	8,965	(9,827)	21,599
Current liabilities					
Current portion of long-term debt	100	300	6	–	406
Short-term debt	140	–	–	–	140
Notes payable to affiliated companies	–	376	3	(379)	–
Derivative liabilities	–	161	29	–	190
Other current liabilities	261	941	902	(182)	1,922
Total current liabilities	501	1,778	940	(561)	2,658
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	320	1,258	(382)	1,196
Regulatory liabilities	–	1,103	1,293	114	2,510
Other liabilities and deferred credits	26	1,284	1,969	(6)	3,273
Total deferred credits and other liabilities	26	2,707	4,520	(274)	6,979
Total capitalization and liabilities	$14,169	$13,304	$14,425	$(10,662)	$31,236

Condensed Consolidating Balance Sheet
December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$8,790	$9,385	$118	$18,293
Current assets					
Cash and cash equivalents	88	73	19	–	180
Notes receivable from affiliated companies	34	44	131	(209)	–
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Income taxes receivable	34	56	104	–	194
Prepayments and other current assets	14	1,082	1,336	(172)	2,260
Total current assets	170	1,916	1,815	(381)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	417	672	–	1,089
Other assets and deferred debits	155	196	953	(555)	749
Total deferred debits and other assets	12,079	1,937	2,868	(8,824)	8,060
Total assets	$12,249	$12,643	$14,068	$(9,087)	$29,873
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$8,687	$3,519	$4,729	$(8,248)	$8,687
Noncontrolling interests	–	3	4	(1)	6
Total equity	8,687	3,522	4,733	(8,249)	8,693
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	8,416	(8,401)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	3	(209)	–
Derivative liabilities	31	380	84	(2)	493
Other current liabilities	220	964	930	(171)	1,943
Total current liabilities	820	1,921	1,127	(382)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Other liabilities and deferred credits	45	1,481	2,427	(10)	3,943
Total deferred credits and other liabilities	46	2,675	4,525	(304)	6,942
Total capitalization and liabilities	$12,249	$12,643	$14,068	$(9,087)	$29,873

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$108	$1,079	$1,282	$(198)	$2,271
Investing activities					
Gross property additions	–	(1,449)	(858)	12	(2,295)
Nuclear fuel additions	–	(78)	(122)	–	(200)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	–	1	–	1
Proceeds from sales of assets to affiliated companies	–	–	11	(11)	–
Purchases of available-for-sale securities and other investments	–	(1,548)	(802)	–	(2,350)
Proceeds from available-for-sale securities and other investments	–	1,558	756	–	2,314
Changes in advances to affiliated companies	4	(2)	(172)	170	–
Contributions to consolidated subsidiaries	(688)	–	–	688	–
Return of investment in consolidated subsidiaries	12	–	–	(12)	–
Other investing activities	–	–	(2)	–	(2)
Net cash (used) provided by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock	623	–	–	–	623
Dividends paid on common stock	(693)	–	–	–	(693)
Dividends paid to parent	–	(1)	(200)	201	–
Dividends paid to parent in excess of retained earnings	–	–	(12)	12	–
Payments of short-term debt with original maturities greater than 90 days	(29)	–	–	–	(29)
Net decrease in short-term debt	(500)	(371)	(110)	–	(981)
Proceeds from issuance of long-term debt, net	1,683	–	595	–	2,278
Retirement of long-term debt	–	–	(400)	–	(400)
Cash distributions to noncontrolling interests	–	(3)	–	(3)	(6)
Changes in advances from affiliated companies	–	170	–	(170)	–
Contributions from parent	–	653	49	(702)	–
Other financing activities	(2)	(9)	12	13	14
Net cash provided (used) by financing activities	1,082	439	(66)	(649)	806
Net increase (decrease) in cash and cash equivalents	518	(1)	28	–	545
Cash and cash equivalents at beginning of year	88	73	19	–	180
Cash and cash equivalents at end of year	$606	$72	$47	$–	$725

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$(90)	$221	$1,114	($27)	$1,218
Investing activities					
Gross property additions	–	(1,553)	(794)	14	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	13	–	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(800)	–	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	746	–	1,534
Changes in advances to affiliated companies	123	105	8	(236)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Return of investment in consolidated subsidiaries	20	10	–	(30)	–
Other investing activities	–	(2)	–	–	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,006)	(163)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Dividends paid to parent in excess of retained earnings	–	–	(20)	20	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to noncontrolling interests	–	(85)	(10)	10	(85)
Changes in advances from affiliated companies	–	(21)	(215)	236	–
Contributions from parent	–	85	29	(114)	–
Other financing activities	–	1	(32)	5	(26)
Net cash (used) provided by financing activities	(42)	1,216	(116)	190	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(8)	–	(75)
Cash and cash equivalents at beginning of year	185	43	27	–	255
Cash and cash equivalents at end of year	$88	$73	$19	$–	$180

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$76	$489	$835	$(148)	$1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	625	(1)	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	–	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	791	–	1,452
Changes in advances to affiliated companies	(99)	(112)	(79)	290	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(7)	36	30
Net cash provided (used) by investing activities	231	(1,291)	(384)	(13)	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(483)	493	–
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)
Cash distributions to noncontrolling interests	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	129	(280)	–
Contributions from parent	–	10	44	(54)	–
Other financing activities	–	49	14	2	65
Net cash (used) provided by financing activities	(275)	805	(496)	161	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

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2009				
Operating revenues	**$2,442**	**$2,312**	**$2,824**	**$2,307**
Operating income	**393**	**379**	**676**	**324**
Income from continuing operations	**183**	**175**	**350**	**132**
Net income	**183**	**174**	**248**	**156**
Net income attributable to controlling interests	**182**	**174**	**247**	**154**
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	**0.66**	**0.62**	**1.24**	**0.46**
Net income attributable to controlling interests	**0.66**	**0.62**	**0.88**	**0.55**
Dividends declared per common share	**0.620**	**0.620**	**0.620**	**0.620**
Market price per share – High	**40.85**	**38.20**	**40.05**	**42.20**
– Low	**31.35**	**33.50**	**35.97**	**36.67**
2008[a]				
Operating revenues	$2,066	$2,244	$2,696	$2,161
Operating income	365	406	591	321
Income from continuing operations	153	200	309	116
Net income	214	205	310	107
Net income attributable to controlling interests	209	205	309	107
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.57	0.76	1.18	0.44
Net income attributable to controlling interests	0.80	0.78	1.18	0.41
Dividends declared per common share	0.615	0.615	0.615	0.620
Market price per share – High	49.16	43.58	45.52	45.60
– Low	40.54	41.00	40.11	32.60

(a) Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

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. Typically, 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 overall operating results may fluctuate substantially on a seasonal basis. During the fourth quarter of 2009, we recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $16 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to previously issued or current period financial statements.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2009				
Operating revenues	**$1,178**	**$1,076**	**$1,307**	**$1,066**
Operating income	**249**	**182**	**367**	**168**
Net income	**128**	**94**	**208**	**84**
Net income attributable to controlling interests	**128**	**95**	**208**	**85**
2008[a]				
Operating revenues	$1,068	$1,048	$1,266	$1,047
Operating income	240	205	353	198
Net income	123	104	201	106
Net income attributable to controlling interests	123	104	201	106

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

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. Typically, weather conditions in PEC's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $16 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to previously issued or current period financial statements.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2009				
Operating revenues	**$1,262**	**$1,234**	**$1,516**	**$1,239**
Operating income	**140**	**195**	**314**	**153**
Net income	**89**	**119**	**177**	**77**
2008				
Operating revenues	$996	$1,194	$1,428	$1,113
Operating income	122	198	236	124
Net income	67	125	143	50

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. Typically, weather conditions in PEF's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

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 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 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, 2009. 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 and Corporate Performance Committee (Audit Committee) of the board of directors.

Based on our assessment, management determined that, at December 31, 2009, 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, 2009, 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, 2009, 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, 2009, 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 as of December 31, 2009, 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 and consolidated financial statement schedule as of and for the year ended December 31, 2009, of the Company and our report dated February 26, 2010, expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

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, 2009. 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, 2009, PEC maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEC's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEC's independent 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, 2009 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, 2009. 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, 2009, PEF maintained effective internal control over financial reporting.

This annual report does not include an attestation report of PEF's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PEF's independent 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, 2009 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 regarding Progress Energy's directors is set forth in Progress Energy's definitive proxy statement for the 2010 Annual Meeting of Shareholders and incorporated by reference herein. Information regarding PEC's directors is set forth in PEC's definitive proxy statement for the 2010 Annual Meeting of Shareholders and incorporated by reference herein.

b) Information regarding 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/investor 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) Information regarding the Audit and Corporate Performance Committee of Progress Energy's Board of Directors is set forth in Progress Energy's definitive proxy statement for the 2010 Annual Meeting of Shareholders and incorporated by reference herein.

PEC does not have a separate audit committee. Information regarding the responsibilities of the Audit and Corporate Performance Committee of Progress Energy's Board with respect to PEC is set forth in PEC's definitive proxy statement for the 2010 Annual Meeting of Shareholders and incorporated by reference herein.

e) 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.

f) 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 2010 Annual Meeting of Shareholders and incorporated by reference herein.

g) 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 regarding Progress Energy's executive compensation and certain matters related to the Organization and Compensation Committee of Progress Energy's Board is set forth in Progress Energy's definitive proxy statement for the 2010 Annual Meeting of Shareholders and incorporated by reference herein. Information regarding PEC's executive compensation and PEC's decision to delegate authority to approve senior management compensation to the Organization and Compensation Committee of Progress Energy's Board rather than having its own standing compensation committee is set forth in PEC's definitive proxy statement for the 2010 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 2010 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 2010 Annual Meeting of Shareholders and incorporated herein by reference.

b) Information regarding the 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 2010 Annual Meeting of Shareholders and incorporated by reference herein.

c) Information regarding 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 2010 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 regarding certain relationships and related transactions is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2010 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 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. These policies and procedures apply to Progress Energy and its subsidiaries. The Progress Energy Controller is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the preapproval policy, the Audit Committee specifically preapproved the use of Deloitte for audit, audit-related, tax and nonaudit services.

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 could include circumstances in which proposed services provide significant economic or other benefits to us. 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. Nonaudit services that are specifically prohibited under Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting Oversight Board rules are specifically prohibited under the policy. Prior to the approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the service, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between Progress Energy and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than Progress Energy) with respect to the promoting, marketing or recommending of a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

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 2010 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.

	2009	2008
Audit fees	**$1,763,000**	$1,769,000
Audit-related fees	**54,000**	51,000
Tax fees	**4,000**	4,000
Total	**$1,821,000**	$1,824,000

Audit fees include fees billed for services rendered in connection with (i) the audits of the annual financial statements of PEF, (ii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of PEF, (iii) accounting consultations arising as part of the audits and (iv) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions.

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.

The Audit Committee has concluded that the provision of the nonaudit services listed above as Tax 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:

   Consolidated Financial Statement Schedules for the Years Ended December 31, 2009, 2008 and 2007.

   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.

3. Exhibits Filed:

   See EXHIBIT INDEX

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 on the balance sheet from the related assets:					
DECEMBER 31, 2009					
Uncollectible accounts	**$18**	**$32**	**$–**	**$(32)**	**$18**
Inventory valuation[b]	**–**	**14**	**–**	**–**	**14**
Fossil fuel plants dismantlement reserve	**145**	**1**	**–**	**(3)**	**143**
Nuclear refueling outage reserve	**14**	**18**	**–**	**(27)**	**5**
DECEMBER 31, 2008					
Uncollectible accounts	$29	$24	$–	$(35)	$18
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	2	12	–	–	14
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

[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] Relates to the impact of PEC's decision to retire 11 coal-fired units prior to the end of their estimated useful lives.

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 Expenses	Other Additions	Deductions [a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
DECEMBER 31, 2009					
Uncollectible accounts	**$6**	**$14**	**$1**	**$(13)**	**$8**
Inventory valuation [b]	**–**	**14**	**–**	**–**	**14**
DECEMBER 31, 2008					
Uncollectible accounts	$6	$10	$–	$(10)	$6
DECEMBER 31, 2007					
Uncollectible accounts	$5	$10	$2	$(11)	$6

[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.

[b] Relates to the impact of the decision to retire 11 coal-fired units prior to the end of their estimated useful lives.

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 Expenses	Other Additions	Deductions [a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
DECEMBER 31, 2009					
Uncollectible accounts	**$11**	**$18**	**$(1)**	**$(18)**	**$10**
Fossil fuel plants dismantlement reserve	**145**	**1**	–	**(3)**	**143**
Nuclear refueling outage reserve	**14**	**18**	–	**(27)**	**5**
DECEMBER 31, 2008					
Uncollectible accounts	$10	$14	$1	$(14)	$11
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	2	12	–	–	14
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

[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.

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.

Date: February 26, 2010

PROGRESS ENERGY, INC.
(Registrant)

By: /s/ William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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 26, 2010
/s/ John D. Baker II (John D Baker II)	Director	February 26, 2010
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	February 26, 2010
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	February 26, 2010
/s/ James B. Hyler, Jr. (James B. Hyler, Jr.)	Director	February 26, 2010
/s/ Robert W. Jones (Robert W. Jones)	Director	February 26, 2010
/s/ W. Steven Jones (W. Steven Jones)	Director	February 26, 2010
/s/ E. Marie McKee (E. Marie McKee)	Director	February 26, 2010
/s/ John H. Mullin, III (John H Mullin, III)	Director	February 26, 2010

/s/ Charles W. Pryor, Jr. (Charles W. Pryor, Jr.)	Director	February 26, 2010
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	February 26, 2010
/s/ Theresa M. Stone (Theresa M. Stone)	Director	February 26, 2010
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	February 26, 2010

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
(Registrant)

Date: February 26, 2010

By: /s/ Lloyd M. Yates
Lloyd M. Yates
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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 26, 2010
/s/ Jeffrey A. Corbett (Jeffrey A. Corbett)	Director	February 26, 2010
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 26, 2010
/s/ John R. McArthur (John R. McArthur)	Director	February 26, 2010
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 26, 2010
/s/ James Scarola (James Scarola)	Director	February 26, 2010
/s/ Frank A. Schiller (Frank A. Schiller)	Director	February 26, 2010
/s/ Paula J. Sims (Paula J. Sims)	Director	February 26, 2010
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	February 26, 2010

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.

Date: February 26, 2010

FLORIDA POWER CORPORATION
(Registrant)

By: /s/ Vincent M. Dolan
Vincent M. Dolan
President and Chief Executive Officer

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior 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 26, 2010
/s/ Vincent M. Dolan (Vincent M. Dolan)	Director	February 26, 2010
/s/ Michael A. Lewis (Michael A. Lewis)	Director	February 26, 2010
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 26, 2010
/s/ John R. McArthur (John R. McArthur)	Director	February 26, 2010
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 26, 2010
/s/ Frank A. Schiller (Frank A. Schiller)	Director	February 26, 2010
/s/ Paula J. Sims (Paula J. Sims)	Director	February 26, 2010

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 May 13, 2009 (filed as Exhibit 3.B to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, File No. 1-15929, 1-3382 and 1-3274).		X	

*3b(3)	By-Laws of Florida Power Corporation, as amended August 24, 2009 (filed as Exhibit 3.1 to the Florida Power Corporation Current Report on Form 8-K, dated August 24, 2009, File No. 1-3274).		X
*4a(1)	Description of Preferred Stock and the rights of the holders thereof (as set forth in Article Fourth of the Restated Charter of Carolina Power & Light Company, as amended, 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).	X	
*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	X	

	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 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); the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated September 12, 2003, File No. 1-3382); the Seventy-third Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 22, 2005, File No. 1-3382); the Seventy-fourth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated November 30, 2005, File No. 1-3382); the Seventy-fifth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated March 13, 2008, File No. 1-3382); the Seventy-sixth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated January 8, 2009, File No. 1-3382); and the Seventy-seventh Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated June 18, 2009, 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	X

	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 Forty-sixth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on September 19, 2007); the Forty-seventh Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on December 13, 2007); and the Forty-eighth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on June 18, 2008).			
*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 Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10(b), File No. 33-25560).		X	
*10a(3)	Power Coordination Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982 (filed as Exhibit 10(c), File No. 33-25560).		X	
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).		X	
*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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).	X	X	X
+*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)	Progress Energy, Inc. 2007 Equity Incentive Plan (filed as Exhibit C to Form DEF 14A, as filed with the SEC on March 30, 2007, File No. 1-15929).	X	X	X
+*10c(9)	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(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 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(15)	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(16)	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(17)	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(18)	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(19)	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(20)	Selected Executives Supplemental Deferred 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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).		X	
+*10c(21)	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 March 1, 2007, File No. 1-3382, No. 1-15929, and No. 1-3274).			
+*10c(22)	Form of Executive and Key Manager 2008 Performance Share Sub-Plan (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended March 31, 2008, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(23)	Form of Restricted Stock Unit Award Agreement (filed as Exhibit 10(b) to Quarterly Report on Form 10-Q for the period ended March 31, 2008, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(24)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., effective January 1, 2009 (filed as Exhibit 10(A) to Quarterly Report on Form 10-Q for the period ended March 31, 2009, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(25)	Executive and Key Manager 2009 Performance Share Sub-Plan (filed as Exhibit 10.1 to Current Report on Form 8-K dated March 17, 2009, File No. 1-15929).	X	X	X
+*10c(26)	Form of Progress Energy, Inc. Restricted Stock Unit Award Agreement (filed as Exhibit 10.2 to Current Report on Form 8-K dated March 17, 2009, File No. 1-15929).	X	X	X
+*10c(27)	Amended Management Incentive Compensation Plan of Progress Energy, Inc., as amended January 1, 2010 (filed as Exhibit 10.3 to Current Report on Form 8-K dated March 17, 2009, File No. 1-15929).	X	X	X
+*10c(28)	Progress Energy, Inc. 2009 Executive Incentive Plan, effective March 17, 2009 (filed as Exhibit D to Form DEF 14A, as filed with the SEC on March 31, 2009, File No. 1-15929)	X		
*10d(1)	Agreement dated November 18, 2004 between Winchester Production Company, Ltd., TGG Pipeline Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 10d(1) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X		X

*10d(2)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company ("SNG"), Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between SNG and PEF, dated December 2, 2004; b) Gas Sale and Purchase Contract between BG and PEF, dated December 1, 2004; c) Interim Firm Transportation Service Agreement by and between FGT and PEF, dated December 2, 2004; d) Letter Agreement between FGT and PEF, dated December 2, 2004 and Firm Transportation Service Agreement by and between FGT and PEF to be entered into upon satisfaction of certain conditions precedent; e) Discount Agreement between FGT and PEF, dated December 2, 2004; f) Amendment to Gas Sale and Purchase Contract between BG and PEF, dated January 28, 2005; and 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
*10d(3)	Engineering, Procurement and Construction Agreement, dated as of December 31, 2008, between Florida Power Corporation d/b/a/ Progress Energy Florida, Inc., as owner, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for a two-unit AP1000 Nuclear Power Plant (filed as Exhibit 10.1 to Current Report on Form 8-K filed on March 2, 2009). (The Registrants' have requested confidential treatment for certain portions of this exhibit pursuant to an application for confidential treatment submitted to the SEC. 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
101.INS	XBRL Instance Document**	X		
101.SCH	XBRL Taxonomy Extension Schema Document	X		
101.CAL	XBRL Taxonomy Calculation Linkbase Document	X		
101.LAB	XBRL Taxonomy Label Linkbase Document	X		
101.PRE	XBRL Taxonomy Presentation Linkbase Document	X		
101.DEF	XBRL Taxonomy Defination Linkbase Document	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.
**Attached as Exhibit 101 are the following financial statements and notes thereto for Progress Energy from the Annual Report on Form 10-K for the year ended December 31, 2009, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statement of Cash Flows, (iv) the Consolidated Statements of Changes in Total Equity, (v) the Consolidated Statements of Comprehensive Income and (vi) the Notes to the Consolidated Financial Statements, tagged as blocks of text.

In accordance with Rule 406T of Regulation S-T, the XBRL-related information in Exhibit 101 to this Annual Report on Form 10-K is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act, is deemed not filed for purposes of Section 18 of the Exchange Act and otherwise is not subject to liability under these sections.

Exhibit No. 12(a)

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31

(dollars in millions)	**2009**	2008	2007	2006	2005
EARNINGS, AS DEFINED:					
Income from continuing operations	**$840**	$778	$702	$567	$527
Fixed charges, as below	**737**	698	625	652	607
Preferred dividend requirements	**(7)**	(7)	(7)	(7)	(6)
Income from continuing operations attributable to noncontrolling interests, net of tax	**(4)**	(5)	(9)	(16)	(4)
Income taxes, as below	**392**	390	329	334	293
Total earnings, as defined	**$1,958**	$1,854	$1,640	$1,530	$1,417
FIXED CHARGES, AS DEFINED:					
Interest on long-term debt	**$667**	$618	$553	$619	$565
Other interest	**51**	61	52	12	23
Imputed interest factor in rentals – charged principally to operating expenses	**12**	12	13	14	13
Preferred dividend requirements of subsidiaries	**7**	7	7	7	6
Total fixed charges, as defined	**$737**	$698	$625	$652	$607
INCOME TAXES:					
Income tax expense (benefit)	**$397**	$395	$334	$339	$298
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(5)	(5)
Total income taxes	**$392**	$390	$329	$334	$293
Ratio of Earnings to Fixed Charges	**2.66**	2.66	2.62	2.35	2.33

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)	**2009**	2008	2007	2006	2005
EARNINGS, AS DEFINED:					
Net income	**$514**	$534	$501	$457	$493
Fixed charges, as below	**212**	227	223	225	205
Income attributable to noncontrolling interests, net of tax	**2**	–	–	–	–
Income taxes, as below	**272**	293	290	260	234
Total earnings, as defined	**$1,000**	$1,054	$1,014	$942	$932
FIXED CHARGES, AS DEFINED:					
Interest on long-term debt	**$197**	$210	$214	$218	$191
Other interest	**10**	9	1	(1)	6
Imputed interest factor in rentals – charged principally to operating expenses	**5**	8	8	8	8
Total fixed charges, as defined	**212**	227	223	225	205
Preferred dividends, as defined	**5**	5	5	5	4
Total fixed charges and preferred dividends combined	**$217**	$232	$228	$230	$209
INCOME TAXES:					
Income tax expense	**$277**	$298	$295	$265	$239
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(5)	(5)
Total income taxes	**$272**	$293	$290	$260	$234
Ratio of Earnings to Fixed Charges	**4.72**	4.64	4.55	4.19	4.55
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.61**	4.54	4.45	4.10	4.46

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)	**2009**	2008	2007	2006	2005
EARNINGS, AS DEFINED:					
Net income	**$462**	$385	$317	$328	$260
Fixed charges, as below	**261**	239	188	159	138
Income taxes	**209**	181	144	193	121
Total earnings, as defined	**$932**	$805	$649	$680	$519
FIXED CHARGES, AS DEFINED:					
Interest on long-term debt	**$239**	$220	$157	$145	$116
Other interest	**19**	16	28	10	18
Imputed interest factor in rentals – charged principally to operating expenses	**3**	3	3	4	4
Total fixed charges, as defined	**261**	239	188	159	138
Preferred dividends, as defined	**2**	2	2	2	2
Total fixed charges and preferred dividends combined	**$263**	$241	$190	$161	$140
Ratio of Earnings to Fixed Charges	**3.57**	3.37	3.45	4.28	3.76
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**3.54**	3.34	3.42	4.22	3.71

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, 2009. 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. 333−70332 on Form S−8, Registration Statement No. 333−78157 on Form S−4, Registration Statement No. 333-104951 on Form S-8, Registration Statement No. 333-104952 on Form S-8, Registration Statement No. 333-155418 on Form S-3, Registration Statement No. 333-155418-03 on Form S-3, Registration Statement No. 333-155418-04 on Form S-3, Registration Statement No. 333-155418-05 on Form S-3, Registration Statement No. 333−155541 on Form S−8 and Registration Statement No. 333−155543 on Form S−8 of our reports dated February 26, 2010, relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc. 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, 2009.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

Exhibit No. 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333–155418-02 on Form S–3 of our report dated February 26, 2010, relating to the consolidated financial statements and consolidated financial statement schedule of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) appearing in this Annual Report on Form 10-K of PEC for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

Exhibit No. 23(c)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-155418-01 on Form S-3 of our report dated February 26, 2010, relating to the financial statements and financial statement schedule of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) appearing in this Annual Report on Form 10-K of PEF for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010