Progress Energy

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COMMISSION
CLERK

March 30, 2012

VIA HAND DELIVERY

Ms. Ann Cole, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 100417-EI; Consummation Report for 2011

Dear Ms. Cole:

Pursuant to Order No. PSC-10-0717-FOF-EI, issued December 8, 2010 in the subject docket, and Rule 25-8.009, Florida Administrative Code, enclosed for filing on behalf of Progress Energy Florida, Inc. is an original and three (3) copies of its Consummation Report for 2011.

Thank you for your assistance in this matter. If you should have any questions, please feel free to contact me at (727) 820-5587.

Sincerely,

R. Alexander Glenn

RAG/lms
Enclosure

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DOCKET NO. 100417-EI

FLORIDA PUBLIC SERVICE COMMISSION

TALLAHASSEE, FLORIDA

CONSUMMATION REPORT

TO

APPLICATION OF

FLORIDA POWER CORPORATION D/B/A
PROGRESS ENERGY FLORIDA, INC.

FOR AUTHORITY TO ISSUE AND SELL

SECURITIES DURING THE TWELVE MONTHS ENDED
DECEMBER 31, 2011

PURSUANT TO FLORIDA STATUTES, SECTION 366.04

AND FLORIDA ADMINISTRATIVE CODE CHAPTER 25-8

Address communications in connection with this Consummation Report to:
R. Alexander Glenn
General Counsel
Progress Energy Florida, Inc.
299 First Avenue North, Suite 151
St. Petersburg, FL 33701
Dated: March 30, 2012

DOCUMENT NUMBER-DATE
01888 MAR 30 12
FPSC-COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	APPLICATION OF FLORIDA POWER CORPORATION D/B/A PROGRESS ENERGY FLORIDA, INC. FOR AUTHORITY TO ISSUE AND SELL SECURITIES DURING THE TWELVE MONTHS ENDED DECEMBER 31, 2011 PURSUANT TO FLORIDA STATUTES SECTION 366.04 AND CHAPTER 25-8, FLORIDA ADMINISTRATIVE CODE	) DOCKET NO. 100417-EI

The Applicant, Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company"), pursuant to Commission Order No. PSC-10-0717-FOF-EI issued December 8, 2010 (the "Order"), and Rule 25-8.009, Florida Administrative Code, hereby files its Consummation Report for the twelve months ended December 31, 2011 as directed by the terms of the Order and states as follows:

The Company did not issue any medium-term notes or other debt or equity securities during calendar year 2011, except for (i) $300,000,000 aggregate principal amount of First Mortgage Bonds; (ii) commercial paper; and (iii) notes that were delivered to evidence loans to the Company from the Utility Money Pool established pursuant to Amended and Restated Utility Money Pool Agreements dated as of October 21, 2009 and September 1, 2011 by and among Progress Energy, Inc., a North Carolina corporation subject to regulation by the Federal Energy Regulatory Commission, and certain of its subsidiaries, including the Company.

The Company typically issues commercial paper for terms up to but not exceeding 270 days from the date of issuance. The commercial paper is issued pursuant to a Commercial Paper

Dealer Agreement dated December 23, 1985 with Merrill Lynch Money Markets Inc., as assigned to and assumed by Banc of America Securities LLC on February 26, 2009, and later assumed through merger by Merrill Lynch, Pierce, Fenner & Smith Incorporated on November 1, 2010 (the "Banc of America Merrill Lynch CP Agreement"), a Letter Agreement dated November 20, 1992 with J.P. Morgan Securities, Inc. (successor to Banc One Capital Markets, Inc., successor to First Chicago Capital Markets, Inc.) (the "J.P. Morgan CP Agreement"), a Letter Agreement dated September 29, 2004 with SunTrust Capital Markets, Inc. (the "SunTrust CP Agreement"), and a Commercial Paper Dealer Agreement dated May 31, 2011 with RBS Securities Inc. (the "RBS CP Agreement"). The commercial paper is sold at a discount, including the underwriting discount of the commercial paper dealer, at a rate comparable to interest rates being paid in the commercial paper market by borrowers of similar creditworthiness. Given the frequency of these sales, it is not practicable to give the details of each issue. However, the Company's 2011 commercial paper activity can be summarized as follows:

2011 Commercial Paper Activity

Commercial paper issued:	$2,660,452,000
Commercial paper matured:	$2,427,540,000
Average outstanding:	$79,323,836
Weighted average yield:	0.41%
Weighted average term:	16.8 days

As back-up for its commercial paper program, the Company has executed a Three-Year Revolving Credit Agreement (the "Three-Year RCA") with Bank of America, N.A., as Administrative Agent for the lenders named therein, dated as of October 15, 2010, providing for long-term loans to the Company in the aggregate principal amount not exceeding $750,000,000.

The Three-Year RCA will expire on October 15, 2013. No loans were made to the Company pursuant to the agreement during 2011.

The Utility Money Pool was established to coordinate and provide for certain short-term cash and working capital requirements of the utility subsidiaries of Progress Energy, Inc. Each utility subsidiary may contribute funds to the Utility Money Pool. No loans through the Utility Money Pool will be made to and no borrowings through the Utility Money Pool will be made by Progress Energy, Inc. The principal amount of each loan from the Utility Money Pool, together with all interest accrued thereon, are to be repaid on demand and in any event within 365 days of the date on which the loan was made. The Company had maximum borrowings of $90,439,128 from the Utility Money Pool during 2011. As of December 31, 2011, the Company had outstanding borrowings from the Utility Money Pool of $8,209,620. The average interest rate on outstanding Money Pool balances was 0.32%.

A statement showing capitalization, pretax interest coverage, and debt interest and preferred stock dividend requirements at December 31, 2011 is attached hereto as Schedule A.

Additional details concerning the foregoing are contained in the following exhibits filed herewith or filed with previous Consummation Reports and incorporated herein by reference (with the exhibit numbers corresponding to the applicable paragraph number of Rule 25-8.009, Florida Administrative Code):

Exhibit No.	**Description of Exhibit**
(1)-a	Three-Year Revolving Credit Agreement, dated as of October 15, 2010, between the Company, the Lenders named therein, and Bank of America, N.A., as Administrative Agent for the Lenders. *(Included as Exhibit (1)-d to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*

Exhibit No.	Description of Exhibit
(1)-b	Commercial Paper Offering Memorandum dated November 2010 of Bank of America Merrill Lynch. *(Included as Exhibit (1)-h to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(1)-c	Commercial Paper Offering Memorandum dated November 2010 of J.P. Morgan Securities LLC. *(Included as Exhibit (1)-i to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(1)-d	Commercial Paper Offering Memorandum dated November 2010 of SunTrust Robinson Humphrey, Inc. *(Included as Exhibit (1)-j to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(1)-e	Commercial Paper Offering Memorandum dated May 2011 of RBS Securities Inc.
(1)-f	Amended and Restated Utility Money Pool Agreement, dated October 21, 2009, between Progress Energy, Inc., Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., a North Carolina corporation, Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation, and Progress Energy Service Company, LLC, a subsidiary service company of Progress Energy and administrative agent. *(Included as Exhibit (1)-l to the Company's Consummation Report filed with the Commission on March 31, 2010 in Docket No. 080640-EI, and incorporated herein by reference.)*
(1)-g	Amended and Restated Utility Money Pool Agreement, dated September 1, 2011, between Progress Energy, Inc., Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., a North Carolina corporation, Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation, and Progress Energy Service Company, LLC, a subsidiary service company of Progress Energy and administrative agent.
(1)-h	The Company entered into a Fiftieth Supplemental Indenture, dated as of August 1, 2011, to its Indenture, dated January 1, 1944, as supplemented, (the "Mortgage"), with The Bank of New York Mellon, as Successor Trustee, in connection with the issuance of the Company's First Mortgage Bonds, 3.10% Series due 2021.

Exhibit No.	Description of Exhibit
(2)-a	Opinion of Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan, L.L.P., Counsel to the Company, dated August 18, 2011, to Barclays Capital Inc., Citigroup Global Markets Inc. and Goldman, Sachs & Co., as representatives of the underwriters, regarding the legality of the Fiftieth Supplemental Indenture.
(2)-b	Opinion of R. Alexander Glenn, General Counsel of Florida Power Corporation d/b/a Progress Energy Florida, Inc., on behalf of the Company, dated August 18, 2011, to Barclays Capital Inc., Citigroup Global Markets Inc. and Goldman, Sachs & Co., as representatives of the underwriters, regarding the legality of the Fiftieth Supplemental Indenture.
(2)-c	Opinion of Hunton & Williams LLP, Counsel to the Company, dated October 15, 2010, to Bank of America, N.A., as Administrative Agent for the Lenders, regarding the legality of the Three-Year Revolving Credit Agreement. *(Included as Exhibit (2)-e to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(2)-d	Opinion of R. Alexander Glenn, General Counsel of Progress Energy Florida, Inc., on behalf of the Company, dated October 15, 2010, to Bank of America, N.A., as Administrative Agent for the Lenders, regarding the legality of the Three-Year Revolving Credit Agreement. *(Included as Exhibit (2)-f to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(3)-a	Annual Report on Form 10-K for the fiscal year ended December 31, 2011, filed by the Company with the Securities and Exchange Commission under the Securities Exchange Act of 1934.
(3)-b	Prospectus Supplement to Prospectus dated November 18, 2008 filed with the Securities and Exchange Commission on August 15, 2011.

Exhibit No.	Description of Exhibit
(4)-a	Commercial Paper Dealer Agreement, Assignment and Assumption Agreement dated February 26, 2009 between Merrill Lynch Money Markets, Inc., Banc of America Securities LLC and the Company regarding the assignment and assumption of the Banc of America CP Agreement from Merrill Lynch Money Markets, Inc. to Banc of America Securities LLC. *(Included as Exhibit (4)-c to the Company's Consummation Report filed with the Commission on March 31, 2010 in Docket No. 080640-EI, and incorporated herein by reference.)*
(4)-b	Letter Notice regarding the November 1, 2010 assumption of Banc of America Merrill Lynch CP Agreement from Banc of America Securities LLC to Merrill Lynch, Pierce, Fenner & Smith Incorporated. *(Included as Exhibit (4)-b to the Company's Consummation Report filed with the Commission on March 31, 2011 in Docket No. 090473-EI, and incorporated herein by reference.)*
(4)-c	Letter Agreement dated November 20, 1992 between the Company and J.P. Morgan Securities, Inc. (successor to Banc One Capital Markets, Inc., successor to First Chicago Capital Markets, Inc). relating to the Company's commercial paper. *(Included as Exhibit (d)-2 to the Company's Consummation Report filed with the Commission on March 27, 1997 in Docket No. 951229-EI, and incorporated herein by reference.)*
(4)-d	Letter Agreement, dated September 29, 2004, between the Company and SunTrust Capital Markets, Inc. *(Included as Exhibit (4)-a to the Company's Consummation Report filed with the Commission on March 30, 2005 in Docket No. 030987-EI, and incorporated herein by reference.)*
(4)-e	Commercial Paper Dealer Agreement, dated May 31, 2011, between the Company and RBS Securities Inc.

Respectfully submitted this 30th day of March, 2012.

R. Alexander Glenn
General Counsel
Progress Energy Florida, Inc.
299 First Avenue North, Suite 151
St. Petersburg, FL 33701
Telephone: (727) 820-5184
Attorney for
PROGRESS ENERGY FLORIDA, INC.

FLORIDA POWER CORPORATION
SELECTED FINANCIAL DATA

CAPITALIZATION:

Florida Power's capitalization at December 31, 2011:

Debt:	**Interest Rate**	**Amount Outstanding** (in millions)
First Mortgage bonds		
Maturing 2013 through 2040	5.56% (a)	$ 4,100
Pollution control refunding revenue bonds		
Secured by Mortgage, Maturing 2018 through 2027	0.57% (a)	$ 241
Medium-term notes		
Maturing 2028	6.75% (a)	$ 150
Borrowing under 3-Year Credit Facility		
Facility Expires 2013	NA (a)	$ -
Discount being amortized over term of bonds		$ (9)
Total long-term debt		$ 4,482
Notes payable (Commercial Paper & Credit Facility Borrowings & Money Pool)		$ 241
Total debt		$ 4,723

Preferred stock:

Without sinking funds, not subject to mandatory redemption:

	Dividend Rate	Current Redemption Price	Shares Outstanding	
	4.00% Series	$ 104.25	39,980	$ 4
	4.40% Series	$ 102.00	75,000	$ 8
	4.58% Series	$ 101.00	99,990	$ 10
	4.60% Series	$ 103.25	39,997	$ 4
	4.75% Series	$ 102.00	80,000	$ 8
Total preferred stock			334,967	$ 34
Common stock equity				$ 4,675
Total capitalization				$ 9,432

(a) Weighted average interest rate at December 31, 2011

PRE-TAX INTEREST COVERAGE:

Florida Power's pre-tax interest coverage for 2011 was **3.0**

DEBT INTEREST:

Florida Power's debt interest charges for 2011 were **$ 253** million

PREFERRED STOCK DIVIDEND REQUIREMENTS:

Florida Power's preferred stock dividend requirements for 2011 were **$ 1.5** million

EXHIBIT (1)-e

RBS
The Royal Bank of Scotland

Offering Memorandum **May 2011**

Florida Power Corporation d / b / a
Progress Energy Florida, Inc.

$750,000,000

Commercial Paper Notes

SUMMARY OF TERMS

Issuer:	Progress Energy Florida, Inc. (the "Company"), a Florida corporation. The Notes are not obligations of, nor guaranteed by, Progress Energy, Inc., the corporate parent of the Company.
Program Size:	Authorized to a maximum outstanding of $750,000,000.
Securities:	Unsecured commercial paper notes (the "Notes"), ranking pari passu with the Company's other unsubordinated and unsecured indebtedness.
Exemption:	The Notes are exempt from registration under the Securities Act of 1933, as amended (the "Act"), pursuant to Section 3(a)(3) thereof or any other applicable exemption available at the time the Notes are offered or sold.
Maturities:	Up to 270 days from date of issue.
Offering Price:	Par less a discount representing an interest factor or, if interest bearing, at par.
Denominations	The Notes will be issued in minimum denominations of $100,000 and integral multiples of $1,000 in excess thereof.
Redemption:	The Notes will not be redeemable prior to maturity or be subject to voluntary prepayment.
Form:	The Notes will be issued and purchases thereof will be recorded only through the book-entry system of The Depository Trust Company ("DTC"). Beneficial owners will not receive certificates representing their ownership interest in the Notes. The face amount of each Note will be paid upon maturity in immediately available funds to DTC. The Company has been advised by DTC that upon receipt of such payment, DTC will credit, on its book-entry records and transfer system, the accounts of the DTC participants through whom Notes are directly or indirectly owned. Payments by DTC to its participants and by such participants to owners of the Notes or their representatives will be governed by customary practices and standing instructions and will be the sole responsibility of DTC, such DTC participants or such representatives, respectively

Settlement:	Unless otherwise agreed to, same day basis, in immediately available funds.
Use of Proceeds:	The Company intends to use the proceeds of the sale of Notes to meet current working capital and other corporate purposes.
Bank Lines:	The Company has a $750,000,000 revolving credit facility to support the sale of commercial paper notes and for other general corporate borrowing purposes.
Issuing & Paying Agent:	JP Morgan Chase Bank NA

CREDIT RATINGS

Ratings are based on current information furnished to the rating agencies by the Company and information obtained by the rating agencies from other sources. Because ratings may be changed, superseded or withdrawn as a result of changes in, or unavailability of, such information, **a prospective purchaser should verify the current long-term and short-term ratings of the Company before purchasing any Notes.**

BUSINESS OF THE COMPANY

The Company 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, 2010, PEF had a total summer generating capacity (including jointly owned capacity) of 10,025 MW.

The Company'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. The Company is interconnected with 22 municipal and 9 rural electric cooperative systems. At December 31, 2010, the Company was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., the city of Gainesville, Reedy Creek Improvement District, Florida Municipal Power Agency and the city of Winter Park. Major industries in the Company's territory include phosphate rock mining and processing, electronic design and manufacturing, and citrus and other food processing. Other major commercial activities are tourism, health care, construction and agriculture. No single customer accounts for more than 10 percent of the Company's revenues.

The Company's net income available to parent was $451 million, $460 million and $383 million for the years ended December 31, 2010, 2009 and 2008, respectively. The Company's total assets were $14.056 billion and $13.100 billion at December 31, 2010 and 2009, respectively. The Company is subject to the rules and regulations of the Federal Energy Regulatory Commission, the Florida Public Service Commission and the Nuclear Regulatory Commission.

AVAILABLE INFORMATION

The Company is subject to the informational requirements of the Securities Exchange Act of 1934 and, in accordance therewith, files reports and other information with the Securities and Exchange Commission (the "Commission"). Such reports and other information may be inspected without charge at the public reference facilities maintained by the Commission at 100 F Street, NE, Washington, D.C. 20549. Copies thereof may be obtained from the Commission upon payment of the prescribed fees. If available, such reports and other information may also be accessed through the Commission's electronic data gathering, analysis and retrieval system ("EDGAR"), including via the Commission's web site on the Internet (http://www.sec.gov). This website URL is an inactive textual reference only.

DOCUMENTS INCORPORATED BY REFERENCE

The Company files important information, including risk factors, with the SEC, and is incorporating those filings by reference into this Offering Memorandum ("this OM"). The information incorporated by reference is an important part of this OM, and the information subsequently filed with the SEC will automatically update and supersede the information contained or previously incorporated by reference in this OM. The Company incorporates by reference the documents listed below and any future filings made with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act until termination of the offering of the Notes; provided, however, that any information furnished under Item 2.02 or Item 7.01 of any Current Report on Form 8-K is not incorporated, unless and, to the extent, specified as "filed" in any such Current Report on Form 8-K.

- Annual Report on Form 10-K for the year ended December 31, 2010
- Quarterly Reports on Form 10-Q for the quarter ended March 31, 2011
- Current Reports on Form 8-K filed March 15 and April 4, 2011

The Company frequently makes its SEC filings on a joint basis with Progress Energy, Inc., our direct corporate parent, and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), one of our affiliates. Any information included in such SEC filings that relates solely to Progress Energy, Inc. or PEC is not and shall not be deemed to be incorporated by reference into this OM.

ADDITIONAL INFORMATION

If you have any questions or require additional information, please contact: Royal Bank of Scotland Group, plc, 600 Washington Boulevard, Stamford, CT, 06901, Attn: Commercial Paper Origination, (203) 897-4691.

IN MAKING AN INVESTMENT DECISION, YOU SHOULD RELY ON YOUR OWN EXAMINATION OF THE COMPANY AND THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THIS EXAMINATION SHOULD INCLUDE REVIEW OF THE SEC FILINGS AND INFORMATION THAT THE COMPANY HAS MADE PUBLICLY AVAILABLE THAT EXPLAIN THE NATURE OF THE COMPANY'S BUSINESS, INCLUDING VARIOUS RISKS OF INVESTING IN THE COMPANY AND ITS SECURITIES. **YOUR INVESTMENT DECISION SHOULD NOT BE BASED SOLELY ON THIS OM AS IT IS NOT INTENDED TO BE A COMPLETE EXPLANATION OF THE NATURE AND RISKS OF INVESTING IN THE COMPANY AND ITS NOTES.** THE NOTES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS OM. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

THIS OM IS CONFIDENTIAL AND MAY NOT BE REPRODUCED OR DISSEMINATED BY ANYONE OTHER THAN RBS SECURITIES INC. ("RBSSI"). NEITHER RBSSI NOR ANY OF ITS AFFILIATES MAKES ANY REPRESENTATION OR WARRANTY AS TO THE ACCURACY OR COMPLETENESS OF THE INFORMATION CONTAINED OR INCORPORATED BY REFERENCE IN THIS OM. THIS OM IS DATED MATERIAL WHICH IS SUBJECT TO CHANGE OVER TIME. RBSSI IS A SUBSIDIARY OF BANK OF AMERICA CORPORATION. RBSSI AND ITS AFFILIATES MAY HAVE POSITIONS IN, AND MAY EFFECT TRANSACTIONS IN, THE NOTES AND OTHER SECURITIES ISSUED BY THE COMPANY AND RBSSI AND ITS AFFILIATES MAY PERFORM OR SEEK TO PERFORM INVESTMENT BANKING AND OTHER SERVICES FOR THE COMPANY. IN ADDITION, AN AFFILIATE OF RBSSI MAY BE A LENDER TO THE COMPANY AND PROCEEDS FROM THE SALES OF THE NOTES MAY BE USED TO REPAY INDEBTEDNESS OWED TO SUCH LENDING AFFILIATE. YOU ARE ADVISED THAT NEITHER RBSSI NOR ANY OF ITS AFFILIATES HAS ANY OBLIGATION TO DISCLOSE TO YOU ANY NON-PUBLIC INFORMATION THAT MAY BE FURNISHED TO RBSSI OR ANY OF ITS AFFILIATES IN CONNECTION WITH THE FOREGOING.

PRIVATE PLACEMENT MEMORANDUM APPROVAL

Approved: Florida Power Corporation d/b/a Progress Energy Florida, Inc.

By: _____

Name: Thomas F. Moses

Title: Assistant Treasurer

Date: 5/31/11

EXHIBIT (1)-g

AMENDED AND RESTATED
UTILITY MONEY POOL AGREEMENT

This Amended and Restated Utility Money Pool Agreement (the "Agreement"), dated as of September 1, 2011, is made and entered into by and among Progress Energy, Inc. ("Progress Energy"), a North Carolina corporation, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), a North Carolina corporation, Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), a Florida corporation (each a "Party" and collectively, the "Parties"), and Progress Energy Service Company, LLC, a subsidiary service company of Progress Energy and administrative agent hereunder.

WITNESSETH:

WHEREAS, the Parties desire to establish a Money Pool (the "Utility Money Pool") to coordinate and provide for certain of their short-term cash and working capital requirements; and

WHEREAS, the utility subsidiaries that will participate in the Utility Money Pool (each a "Subsidiary" and collectively, the "Subsidiaries") will from time to time have need to borrow funds on a short-term basis, and certain of the Subsidiaries will from time to time have funds available to loan on a short-term basis;

NOW, THEREFORE, in consideration of the premises and the mutual agreements, covenants and provisions contained herein, the Parties hereto agree as follows:

ARTICLE I

CONTRIBUTIONS AND BORROWINGS

Section 1.01 Contributions to Utility Money Pool.

Each Subsidiary will determine each day, on the basis of cash flow projections and other relevant factors, in such Subsidiary's sole discretion, the amount of funds it has available for contribution to the Utility Money Pool, and will contribute such funds to the Utility Money Pool. The determination of whether a Subsidiary at any time has surplus funds to lend to the Utility Money Pool or shall lend funds to the Utility Money Pool will be made by such Subsidiary's chief financial officer or treasurer, or by a designee thereof, on the basis of cash flow projections and other relevant factors, in such Subsidiary's sole discretion. Each Subsidiary may withdraw any of its funds at any time upon notice to Progress Energy Service Company, LLC, as administrative agent of the Utility Money Pool.

Section 1.02 Rights to Borrow.

Subject to the provisions of Section 1.04(c) of this Agreement, the short-term borrowing needs of the Subsidiaries will be met by funds in the Utility Money Pool to the extent such funds are available. Each Subsidiary shall have the right to make short-term borrowings from the Utility Money Pool from time to time, subject to the availability of funds and the limitations and conditions set forth herein and in the applicable orders of regulatory authorities. Each Subsidiary may request loans from the Utility Money Pool from time to time during the period from the date hereof until this Agreement is terminated by written agreement of the Parties; *provided, however,* that the aggregate amount of all loans requested by any Subsidiary hereunder shall not exceed the applicable borrowing limits set forth in applicable orders of regulatory authorities, resolutions of such Subsidiary's Board of Directors, such Subsidiary's governing corporate documents, and agreements binding upon such Subsidiary. No loans through the Utility Money Pool will be made to, and no borrowings through the Utility Money Pool will be made by, Progress Energy.

Section 1.03 Source of Funds.

(a) Funds will be available through the Utility Money Pool from the following sources for use by the Subsidiaries from time to time: (1) surplus funds in the treasuries of Subsidiaries, (2) surplus funds in the treasury of Progress Energy, and (3) proceeds from bank borrowings and/or commercial paper sales by Parties ("External Funds"), in each case to the extent permitted by applicable laws and regulatory orders. Funds will be made available from such sources in such order as Progress Energy Service Company, LLC, as administrator of the Utility Money Pool, may determine is appropriate, in its sole discretion, consistent with the individual borrowing needs and financial standing of the Subsidiaries providing funds to the Utility Money Pool.

(b) Borrowing Subsidiaries will borrow *pro rata* from each lending Party in the proportion that the total amount loaned by such lending Party bears to the total amount then loaned through the Utility Money Pool. On any day when more than one funding source (*e.g.*, surplus treasury funds of Progress Energy and any Subsidiary ("Internal Funds") and External Funds), with different rates of interest, is used to fund loans through the Utility Money Pool, each borrowing Subsidiary will borrow *pro rata* from each funding source in the same proportion that the amount of funds provided by that funding source bears to the total amount of short-term funds available to the Utility Money Pool.

Section 1.04 Authorization.

(a) Each loan shall be authorized by the lending Party's chief financial officer or treasurer, or by a designee thereof.

(b) Progress Energy Service Company, LLC, as administrator of the Utility Money Pool, will provide each Party with periodic activity and cash accounting reports that include, among other things, reports of cash activity, the daily balance of loans outstanding and the calculation of interest charged.

(c) All borrowings from the Utility Money Pool shall be authorized by the borrowing Subsidiary's chief financial officer or treasurer, or by a designee thereof. No Subsidiary shall be required to effect a borrowing through the Utility Money Pool if such Subsidiary determines that it can (and is authorized to) effect such borrowing at lower cost directly from banks or through the sale of its own commercial paper.

Section 1.05 Interest.

The daily outstanding balance of all loans to any Subsidiary shall accrue interest as follows:

(a) If only Internal Funds comprise the daily outstanding balance of all loans outstanding during a calendar month, the interest rate applicable to such daily balances shall be the rates for high-grade unsecured 30-day commercial paper of major corporations as quoted by Bloomberg Finance.

(b) If only External Funds comprise the daily outstanding balance of all loans outstanding during a calendar month, the interest rate applicable to such daily outstanding balance shall be the lending Party's cost for such External Funds or, if more than one Party had made available External Funds at any time during the month, the applicable interest rate shall be a composite rate, equal to the weighted average of the costs incurred by the respective Parties for such External Funds.

(c) In cases where the daily outstanding balances of all loans outstanding at any time during the month include both Internal Funds and External Funds, the interest rate applicable to the daily outstanding balances for the month shall be equal to the weighted average of the (i) cost of all Internal Funds contributed by Parties, as determined pursuant to Section 1.05(a) of this Agreement, and (ii) the cost of all such External Funds, as determined pursuant to Section 1.05(b) of this Agreement.

The interest rate applicable to Loans made by Parties to the Utility Money Pool under Section 1.03(a) of this Agreement shall be equal to the rate determined pursuant to subsection (a), (b) or (c), above, as applicable.

Section 1.06 Certain Costs.

The cost of compensating balances and fees paid to banks to maintain credit lines by Parties lending External Funds to the Utility Money Pool shall initially be paid by the Party maintaining such line. A portion of such costs shall be retroactively allocated every month to the Subsidiaries borrowing such External Funds through the Utility Money Pool in proportion to their respective daily outstanding borrowings of such External Funds.

Section 1.07 Repayment.

Each Subsidiary receiving a loan from the Utility Money Pool hereunder shall repay the principal amount of such loan, together with all interest accrued thereon, on demand. All loans made through the Utility Money Pool may be prepaid by the borrower without premium or penalty.

Section 1.08 Form of Loans to Subsidiaries.

Loans to the Subsidiaries from the Utility Money Pool shall be made as open-account advances, pursuant to the terms of this Agreement. A separate promissory note will not be required for each individual transaction. Instead, a promissory note evidencing the terms of the transactions shall be signed by the Subsidiaries. Any such note shall: (a) be in substantially the form of the note attached hereto; (b) be dated as of the date of this Agreement; (c) mature on demand or on a date agreed by the Parties to the transaction; and (d) be repayable in whole at any time or in part from time to time, without premium or penalty.

ARTICLE II

OPERATION OF UTILITY MONEY POOL

Section 2.01 Operation.

Operation of the Utility Money Pool, including record keeping and coordination of loans, will be handled by Progress Energy Service Company, LLC under the authority of the appropriate officers of the Parties. Progress Energy Service Company, LLC shall be responsible for the determination of all applicable interest rates and charges to be applied to advances outstanding at any time hereunder, shall maintain records of all advances, interest charges and accruals and interest and principal payments for purposes hereof, and shall prepare periodic reports thereof for the Parties. Progress Energy Service Company, LLC will administer the Utility Money Pool on an "at cost" basis. Separate records shall be kept by Progress Energy Service Company, LLC for the Utility Money Pool established by this Agreement and any other money pool administered by Progress Energy Service Company, LLC.

Section 2.02 Investment of Surplus Funds in the Utility Money Pool.

Funds not required for the Utility Money Pool loans (with the exception of funds required to satisfy the Utility Money Pool's liquidity requirements) will ordinarily be invested in one or more short-term investments using products determined by Progress Energy Service Company, LLC.

Section 2.03 Allocation of Interest Income and Investment Earnings.

The interest income and other investment income earned by the Utility Money Pool on loans and investment of surplus funds will be allocated among the Parties in accordance with the proportion each Party's contribution of funds in the Utility Money Pool bears to the total amount

of funds in the Utility Money Pool and the cost of any External Funds provided to the Utility Money Pool by such Party. Interest and other investment earnings will be computed on a daily basis and settled once per month.

Section 2.04 Event of Default.

If any Subsidiary shall generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors, or any proceeding shall be instituted by or against any Subsidiary seeking to adjudicate it bankrupt or insolvent, then Progress Energy Service Company, LLC, on behalf of the Utility Money Pool, may, by notice to the Subsidiary, terminate the Utility Money Pool's commitment to the Subsidiary and/or declare the principal amount then outstanding of, and the accrued interest on, the loans and all other amounts payable to the Utility Money Pool by the Subsidiary hereunder to be forthwith due and payable, whereupon such amounts shall be immediately due and payable without presentment, demand, protest or other formalities of any kind, all of which are hereby expressly waived by each Subsidiary.

ARTICLE III

MISCELLANEOUS

Section 3.01 Amendments.

No amendment to this Agreement shall be adopted except in a writing executed by the Parties and subject to all applicable approvals by regulatory authorities.

Section 3.02 Legal Responsibility.

Nothing herein contained shall render any Party liable for the obligations of any other Party hereunder and the rights, obligations and liabilities of the Parties are several in accordance with their respective obligations, and not joint.

Section 3.03 Rules for Implementation.

The Parties may develop a set of guidelines for implementing the provisions of this Agreement, provided that the guidelines are consistent with all of the provisions of this Agreement.

Section 3.04 Governing Law.

This Agreement shall be governed by and construed in accordance with, the laws of the State of North Carolina, without regard to the conflicts of laws provisions thereof.

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party hereto as of the date first above written.

PROGRESS ENERGY, INC.

By: _____
Name: Sherri L. Green
Title: Treasurer

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

By: _____
Name: Sherri L. Green
Title: Treasurer

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

By: _____
Name: Sherri L. Green
Title: Treasurer

PROGRESS ENERGY SERVICE COMPANY, LLC (as administrator)

By: _____
Name: Sherri L. Green
Title: Treasurer

FORM OF NOTE TO BE EXECUTED BY BORROWING APPLICANT TO UTILITY MONEY POOL AGREEMENT

FOR VALUE RECEIVED, the undersigned, **Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.** (the "Borrower"), hereby promises to pay to the order of the Utility Money Pool at its principal office in Raleigh, North Carolina, on demand, the principal sums borrowed from time to time under the Utility Money Pool Agreement (the "Principal Amount Outstanding"). This note may be prepaid in full at any time or in part from time to time without premium or penalty. The Principal Amount Outstanding shall bear interest, calculated daily, at the appropriate rate per Section 1.05 of the Utility Money Pool Agreement.

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(Name of Borrower)

By: _____
Title: Treasurer
Date: September 1, 2011

FORM OF NOTE TO BE EXECUTED BY BORROWING APPLICANT TO UTILITY MONEY POOL AGREEMENT

FOR VALUE RECEIVED, the undersigned, **Florida Power Corporation d/b/a Progress Energy Florida, Inc.** (the "Borrower"), hereby promises to pay to the order of the Utility Money Pool at its principal office in Raleigh, North Carolina, on demand, the principal sums borrowed from time to time under the Utility Money Pool Agreement (the "Principal Amount Outstanding"). This note may be prepaid in full at any time or in part from time to time without premium or penalty. The Principal Amount Outstanding shall bear interest, calculated daily, at the appropriate rate per Section 1.05 of the Utility Money Pool Agreement.

Florida Power Corporation
d/b/a Progress Energy Florida, Inc.
(Name of Borrower)

By: _____
Title: Treasurer
Date: September 1, 2011

APPOINTMENT OF DESIGNEES

Pursuant to Sections 1.01, 1.04(a) and 1.04(c) of the Amended and Restated Utility Money Pool Agreement, the following individuals are considered "a designee" for purposes of determining a) whether a Subsidiary has surplus funds to lend into the Utility Money Pool or needs to borrow from the Utility Money Pool and b) taking the appropriate actions to lend to or borrow from the Utility Money Pool based upon cash flow projections and other relevant factors:

Thomas Moses
Kenneth Long
Patricia Bass
Martha Korpela
Michael T. Lewis

By: _____
Name: Sherri L. Green
Title: Treasurer
Date: September 1, 2011

EXHIBIT (1)-h

This instrument was prepared
under the supervision of:
R. Alexander Glenn, General Counsel
Florida Power Corporation
d/b/a Progress Energy Florida, Inc.
299 First Avenue North
St. Petersburg, Florida 33701

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

TO

THE BANK OF NEW YORK MELLON, TRUSTEE

FIFTIETH SUPPLEMENTAL INDENTURE

Dated as of August 1, 2011

This is a security agreement covering personal property as well as a mortgage upon real estate and other property.

SUPPLEMENT TO INDENTURE
DATED AS OF JANUARY 1, 1944, AS SUPPLEMENTED

NOTE TO RECORDER: Nonrecurring Intangible Taxes and Documentary Stamp Taxes have been collected by the Pinellas County Circuit Court Clerk. With respect to the Nonrecurring Intangible Taxes due, the Intangible Tax Base was calculated in compliance with Subsections (1) and (2) of Section 199.133 of the Florida Statutes and is $30,300,000.

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* The headings listed in this Table of Contents are for convenience only and should not be included for substantive purposes as part of this Supplemental Indenture.

RECITALS

SUPPLEMENTAL INDENTURE, dated as of the 1st day of August 2011, made and entered into by and between **FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.**, a corporation of the State of Florida (hereinafter sometimes called the "Company"), party of the first part, and **THE BANK OF NEW YORK MELLON** (formerly known of record as The Bank of New York), a New York banking corporation, whose post office address is 101 Barclay Street, New York, New York 10286, as successor trustee (hereinafter sometimes called the "Trustee"), party of the second part.

WHEREAS, the Company has heretofore executed and delivered an indenture of mortgage and deed of trust, titled the Indenture, dated as of January 1, 1944, and the same has been recorded in the public records and on the dates listed on **Exhibit A** hereto, and for the purpose of preventing the extinguishment of said Indenture under Chapter 712, Florida Statutes, the above-referred-to Indenture applicable to each county in which this instrument is recorded is hereby incorporated herein and made a part hereof by this reference thereto (said Indenture is hereinafter referred to as the "Original Indenture" and with the below-mentioned forty-nine Supplemental Indentures and this Supplemental Indenture and all other indentures, if any, supplemental to the Original Indenture collectively referred to as the "Indenture"), in and by which the Company conveyed and mortgaged to the Trustee certain property therein described to secure the payment of all bonds of the Company to be issued thereunder in one or more series; and

WHEREAS, pursuant to and under the terms of the Original Indenture, the Company issued $16,500,000 First Mortgage Bonds, 3 3/8% Series due 1974; and

WHEREAS, subsequent to the date of the execution and delivery of the Original Indenture, the Company has from time to time executed and delivered forty-nine indentures supplemental to the Original Indenture (together with this Supplemental Indenture, collectively, the "Supplemental Indentures"), providing for the creation of additional series of bonds secured by the Original Indenture and/or for amendment of certain terms and provisions of the Original Indenture and of indentures supplemental thereto, such Supplemental Indentures, and the purposes thereof, being as follows:

Supplemental Indenture and Date	Providing for:
First July 1, 1946	$4,000,000 First Mortgage Bonds, 2 7/8% Series due 1974
Second November 1, 1948	$8,500,000 First Mortgage Bonds, 3 1/4% Series due 1978
Third July 1, 1951	$14,000,000 First Mortgage Bonds, 3 3/8% Series due 1981
Fourth November 1, 1952	$15,000,000 First Mortgage Bonds, 3 3/8% Series due 1982
Fifth November 1, 1953	$10,000,000 First Mortgage Bonds, 3 5/8% Series due 1983

Supplemental Indenture and Date	Providing for:
Sixth July 1, 1954	$12,000,000 First Mortgage Bonds, 3 1/8% Series due 1984
Seventh July 1, 1956	$20,000,000 First Mortgage Bonds, 3 7/8% Series due 1986, and amendment of certain provisions of the Original Indenture
Eighth July 1, 1958	$25,000,000 First Mortgage Bonds, 4 1/8% Series due 1988, and amendment of certain provisions of the Original Indenture
Ninth October 1, 1960	$25,000,000 First Mortgage Bonds, 4 3/4% Series due 1990
Tenth May 1, 1962	$25,000,000 First Mortgage Bonds, 4 1/4% Series due 1992
Eleventh April 1, 1965	$30,000,000 First Mortgage Bonds, 4 5/8% Series due 1995
Twelfth November 1, 1965	$25,000,000 First Mortgage Bonds, 4 7/8% Series due 1995
Thirteenth August 1, 1967	$25,000,000 First Mortgage Bonds, 6 1/8% Series due 1997
Fourteenth November 1, 1968	$30,000,000 First Mortgage Bonds, 7% Series due 1998
Fifteenth August 1, 1969	$35,000,000 First Mortgage Bonds, 7 7/8% Series due 1999
Sixteenth February 1, 1970	Amendment of certain provisions of the Original Indenture
Seventeenth November 1, 1970	$40,000,000 First Mortgage Bonds, 9% Series due 2000
Eighteenth October 1, 1971	$50,000,000 First Mortgage Bonds, 7 3/4% Series due 2001
Nineteenth June 1, 1972	$50,000,000 First Mortgage Bonds, 7 3/8% Series due 2002
Twentieth November 1, 1972	$50,000,000 First Mortgage Bonds, 7 1/4% Series A due 2002
Twenty-First June 1, 1973	$60,000,000 First Mortgage Bonds, 7 3/4% Series due 2003
Twenty-Second December 1, 1973	$70,000,000 First Mortgage Bonds, 8% Series A due 2003
Twenty-Third October 1, 1976	$80,000,000 First Mortgage Bonds, 8 3/4% Series due 2006
Twenty-Fourth April 1, 1979	$40,000,000 First Mortgage Bonds, 6 3/4-6 7/8% Series due 2004-2009
Twenty-Fifth April 1, 1980	$100,000,000 First Mortgage Bonds, 13 5/8% Series due 1987
Twenty-Sixth November 1, 1980	$100,000,000 First Mortgage Bonds, 13.30% Series A due 1990

Supplemental Indenture and Date	Providing for:
Twenty-Seventh November 15, 1980	$38,000,000 First Mortgage Bonds, 10-10 1/4% Series due 2000-2010
Twenty-Eighth May 1, 1981	$50,000,000 First Mortgage Bonds, 9 1/4% Series A due 1984
Twenty-Ninth September 1, 1982	Amendment of certain provisions of the Original Indenture
Thirtieth October 1, 1982	$100,000,000 First Mortgage Bonds, 13 1/8% Series due 2012
Thirty-First November 1, 1991	$150,000,000 First Mortgage Bonds, 8 5/8% Series due 2021
Thirty-Second December 1, 1992	$150,000,000 First Mortgage Bonds, 8% Series due 2022
Thirty-Third December 1, 1992	$75,000,000 First Mortgage Bonds, 6 1/2% Series due 1999
Thirty-Fourth February 1, 1993	$80,000,000 First Mortgage Bonds, 6-7/8% Series due 2008
Thirty-Fifth March 1, 1993	$70,000,000 First Mortgage Bonds, 6-1/8% Series due 2003
Thirty-Sixth July 1, 1993	$110,000,000 First Mortgage Bonds, 6% Series due 2003
Thirty-Seventh December 1, 1993	$100,000,000 First Mortgage Bonds, 7% Series due 2023
Thirty-Eighth July 25, 1994	Appointment of First Chicago Trust Company of New York as successor Trustee and resignation of former Trustee and Co-Trustee
Thirty-Ninth July 1, 2001	$300,000,000 First Mortgage Bonds, 6.650% Series due 2011
Fortieth July 1, 2002	$240,865,000 First Mortgage Bonds in three series as follows: (i) $108,550,000 Pollution Control Series 2002A Bonds due 2027; (ii) $100,115,000 Pollution Control Series 2002B Bonds due 2022; and (iii) $32,200,000 Pollution Control Series 2002C Bonds due 2018; and reservation of amendment of certain provisions of the Original Indenture
Forty-First February 1, 2003	$650,000,000 First Mortgage Bonds in two series as follows: (i) $425,000,000 4.80% Series due 2013 and (ii) $225,000,000 5.90% Series due 2033; and reservation of amendment of certain provisions of the Original Indenture

Supplemental Indenture and Date	Providing for:
Forty-Second April 1, 2003	Amendment of certain provisions of the Original Indenture; appointment of Bank One, N.A. as successor Trustee and resignation of former Trustee; and reservation of amendment of certain provisions of the Original Indenture
Forty-Third November 1, 2003	$300,000,000 First Mortgage Bonds, 5.10% Series due 2015; and reservation of amendment of certain provisions of the Original Indenture
Forty-Fourth August 1, 2004	Amendment of certain provisions of the Original Indenture
Forty-Fifth May 1, 2005	$300,000,000 First Mortgage Bonds, 4.50% Series due 2010
Forty-Sixth September 1, 2007	$750,000,000 First Mortgage Bonds in two series as follows: (i) $250,000,000 5.80% Series due 2017 and (ii) $500,000,000 6.35% Series due 2037
Forty-Seventh December 1, 2007	Appointment of The Bank of New York Mellon as successor Trustee and resignation of former Trustee
Forty-Eighth June 1, 2008	$1,500,000,000 First Mortgage Bonds in two series as follows: (i) $500,000,000 5.65% Series due 2018 and (ii) $1,000,000,000 6.40% Series due 2038
Forty-Ninth March 1, 2010	$600,000,000 First Mortgage Bonds in two series as follows: (i) $250,000,000 4.55% Series due 2020 and (ii) $350,000,000 5.65% Series due 2040

WHEREAS, such Supplemental Indentures have each been recorded in the public records of the counties listed on **Exhibit A** hereto, on the dates and in the official record books and at the page numbers listed thereon; and

WHEREAS, subsequent to the date of the execution and delivery of the Forty-Ninth Supplemental Indenture the Company has purchased, constructed or otherwise acquired certain property hereinafter referred to, and the Company desires by this Supplemental Indenture to confirm the lien of the Original Indenture on such property; and

WHEREAS, pursuant to the Forty-Seventh Supplemental Indenture, JPMorgan Chase Bank, N.A., resigned as Trustee and The Bank of New York Mellon was appointed as the successor Trustee, effective December 13, 2007; and

WHEREAS, The Bank of New York Mellon is eligible and qualified to serve as Trustee under the Indenture; and

WHEREAS, the Company desires by this Supplemental Indenture to create a new series of bonds to be designated as First Mortgage Bonds, 3.10% Series due 2021 (hereinafter sometimes called the "2021 Bonds" or the "New Series Bonds"), to be issued under the Original Indenture pursuant to Section 2.01 of the Original Indenture, and also desires to deliver to the Trustee prior to or simultaneously with the authentication and delivery of the initial issue of Three Hundred Million Dollars ($300,000,000) principal amount of New Series Bonds pursuant to Section 4.03 of the Original Indenture the documents and instruments required by said section; and

WHEREAS, the Company in the exercise of the powers and authority conferred upon and reserved to it under and by virtue of the Indenture, and pursuant to the resolutions of its Board of Directors (as defined in the Indenture, which definition includes any duly authorized committee of the Board of Directors, including the First Mortgage Bond Indenture Committee of the Board of Directors) has duly resolved and determined to make, execute and deliver to the Trustee a Supplemental Indenture in the form hereof for the purposes herein provided; and

WHEREAS, all conditions and requirements necessary to make this Supplemental Indenture a valid, binding and legal instrument in accordance with its terms have been done, performed and fulfilled, and the execution and delivery hereof have been in all respects duly authorized;

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH: That Florida Power Corporation d/b/a Progress Energy Florida, Inc., in consideration of the premises and of One Dollar ($1.00) and other good and valuable consideration to it duly paid by the Trustee at or before the ensealing and delivery of these presents, the receipt whereof is hereby acknowledged, and in order to secure the payment of both the principal of and interest and premium, if any, on the bonds from time to time issued and to be issued under the Indenture, according to their tenor and effect, does hereby confirm the grant, sale, resale, conveyance, assignment, transfer, mortgage and pledge of the property described in the Original Indenture and the Supplemental Indentures (except such properties or interests therein as may have been released or sold or disposed of in whole or in part as permitted by the provisions of the Original Indenture), and hath granted, bargained, sold, released, conveyed, assigned, transferred, mortgaged, pledged, set over and confirmed, and by these presents doth grant, bargain, sell, release, convey, assign, transfer, mortgage, pledge, set over and confirm unto The Bank of New York Mellon, as Trustee, and to its successors in the trust and to its successors and assigns, forever, all property, real, personal and mixed, tangible and intangible, owned by the Company on the date of the execution of this Supplemental Indenture or which may be hereafter acquired by it, including (but not limited to) all property which it has acquired subsequent to the date of execution of the Forty-Ninth Supplemental Indenture and situated in the State of Florida, including without limitation the property described on **Exhibit B** hereto (in all cases, except such property as is expressly excepted by the Original Indenture from the lien and operation thereof); and without in any way limiting or impairing by the enumeration of the same the scope and intent of the foregoing, all lands, power sites, flowage rights, water rights, water locations, water appropriations, ditches, flumes, reservoirs, reservoir sites, canals, raceways, dams, dam sites, aqueducts and all other rights or means for appropriating, conveying, storing and supplying water; all rights of way and roads; all plants for the generation of electricity by steam, water and/or other power; all power houses, facilities for utilization of natural gas, street lighting systems, if any, standards and other equipment incidental thereto, telephone, radio and television systems, microwave systems, facilities for utilization of water, steam heat and hot water plants, if

any, all substations, lines, service and supply systems, bridges, culverts, tracks, offices, buildings and other structures and equipment and fixtures thereof; all machinery, engines, boilers, dynamos, electric machines, regulators, meters, transformers, generators, motors, electrical and mechanical appliances, conduits, cables, pipes, fittings, valves and connections, poles (wood, metal and concrete), and transmission lines, wires, cables, conductors, insulators, tools, implements, apparatus, furniture, chattels, and choses in action; all municipal and other franchises, consents, licenses or permits; all lines for the distribution of electric current, gas, steam heat or water for any purpose including towers, poles (wood, metal and concrete), wires, cables, pipes, conduits, ducts and all apparatus for use in connection therewith; all real estate, lands, easements, servitudes, licenses, permits, franchises, privileges, rights-of-way and other rights in or relating to real estate or the use and occupancy of the same (except as herein or in the Original Indenture or any of the Supplemental Indentures expressly excepted); all the right, title and interest of the Company in and to all other property of any kind or nature appertaining to and/or used and/or occupied and/or enjoyed in connection with any property hereinbefore, or in the Original Indenture and said Supplemental Indentures, described.

IT IS HEREBY AGREED by the Company that all the property, rights and franchises acquired by the Company after the date hereof (except any property herein or in the Original Indenture or any of the Supplemental Indentures expressly excepted) shall, subject to the provisions of Section 9.01 of the Original Indenture and to the extent permitted by law, be as fully embraced within the lien hereof as if such property, rights and franchises were now owned by the Company and/or specifically described herein and conveyed hereby.

TOGETHER WITH all and singular the tenements, hereditaments and appurtenances belonging or in any way appertaining to the aforesaid mortgaged property or any part thereof, with the reversion and reversions, remainder and remainders and (subject to the provisions of Section 9.01 of the Original Indenture) the tolls, rents, revenues, issues, earnings, income, product and profits thereof, and all the estate, right, title and interest and claim whatsoever, at law as well as in equity, which the Company now has or may hereafter acquire in and to the aforesaid mortgaged property and every part and parcel thereof.

TO HAVE AND TO HOLD THE SAME unto The Bank of New York Mellon, as Trustee, and its successors in the trust and its assigns forever, but **IN TRUST NEVERTHELESS** upon the terms and trusts set forth in the Indenture, for the benefit and security of those who shall hold the bonds and coupons issued and to be issued under the Indenture, without preference, priority or distinction as to lien of any of said bonds and coupons over any others thereof by reason or priority in the time of the issue or negotiation thereof, or otherwise howsoever, subject, however, to the provisions of Sections 10.03 and 10.12 of the Original Indenture.

SUBJECT, HOWEVER, to the reservations, exceptions, conditions, limitations and restrictions contained in the several deeds, servitudes and contracts or other instruments through which the Company acquired, and/or claims title to and/or enjoys the use of the aforesaid properties; and subject also to encumbrances of the character defined in the Original Indenture as "excepted encumbrances" in so far as the same may attach to any of the property embraced herein.

Without derogating from the security and priority presently afforded by the Indenture and by law for all of the bonds of the Company that have been, are being, and may in the future be, issued

pursuant to the Indenture, for purposes of obtaining any additional benefits and security provided by Section 697.04 of the Florida Statutes, the following provisions of this paragraph shall be applicable. The Indenture also shall secure the payment of both principal and interest and premium, if any, on the bonds from time to time hereafter issued pursuant to the Indenture, according to their tenor and effect, and the performance and observance of all the provisions of the Indenture (including any indentures supplemental thereto and any modification or alteration thereof made as therein provided), whether the issuance of such bonds may be optional or mandatory, and for any purpose, within twenty (20) years from the date of this Supplemental Indenture. The total amount of indebtedness secured by the Indenture may decrease or increase from time to time, but the total unpaid balance so secured at any one time shall not exceed the maximum principal amount of $10,000,000,000, plus interest and premium, if any, as well as any disbursements made for the payment of taxes, levies or insurance on the property encumbered by the Indenture, with interest on those disbursements, plus any increase in the principal balance as the result of negative amortization or deferred interest. For purposes of Section 697.04 of the Florida Statutes, the Original Indenture, as well as all of the indentures supplemental thereto that have been executed prior to the date of this Supplemental Indenture, are incorporated herein by this reference with the same effect as if they had been set forth in full herein.

And, upon the consideration hereinbefore set forth, the Company does hereby covenant and agree to and with the Trustee and its successors in trust under the Indenture for the benefit of those who shall hold bonds and coupons issued and to be issued under the Indenture, as follows:

ARTICLE I

THE NEW SERIES BONDS

A. CREATION OF FIRST MORTGAGE BONDS, 3.10% SERIES DUE 2021

Section 1. The Company hereby creates a new series of bonds, not limited in principal amount except as provided in the Original Indenture, to be issued under and secured by the Original Indenture, to be designated by the title "First Mortgage Bonds, 3.10% Series due 2021." The initial issue of the 2021 Bonds shall consist of Three Hundred Million Dollars ($300,000,000) principal amount thereof. Subject to the terms of the Indenture, the principal amount of the 2021 Bonds is unlimited. The Company may, at its option in the future, issue additional 2021 Bonds.

The 2021 Bonds shall be issued only as registered bonds without coupons in the denomination of Two Thousand Dollars ($2,000) and any integral multiple of One Thousand Dollars ($1,000) above that amount.

Section 2. (a) The 2021 Bonds shall be issued in registered form without coupons and shall be issued initially in the form of one or more Global Bonds (each such Global Bond, a "2021 Global Bond") to or on behalf of The Depository Trust Company ("DTC"), as depositary therefor (in such capacity, the "Depositary"), and registered in the name of such Depositary or its nominee. Any 2021 Bonds to be issued or transferred to, or to be held by or on behalf of DTC as such Depositary or such nominee (or any successor of such nominee) for such purpose shall bear the depositary legends in substantially the form set forth at the top of the form of the 2021 Bonds in Section B of this Article I, unless otherwise agreed by the Company, and in the case of a

successor Depositary, such legend or legends as such Depositary and/or the Company shall require and to which each shall agree, in each case such agreement to be confirmed in writing to the Trustee. Principal of, and interest on, the 2021 Bonds and the Redemption Price (as defined below), if applicable, will be payable, the transfer of the 2021 Bonds will be registrable and the 2021 Bonds will be exchangeable for the 2021 Bonds bearing identical terms and provisions, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York; *provided, however,* that payment of interest may be made at the option of the Company by check mailed to the registered holders thereof at their registered address; and *further provided, however,* that with respect to a 2021 Global Bond, the Company may make payments of principal of, and interest on, the 2021 Global Bond and the Redemption Price, if applicable, and interest on such 2021 Global Bond pursuant to and in accordance with such arrangements as are agreed upon by the Company and the Depositary for such 2021 Global Bond. The New Series Bonds shall have the terms set forth in the form of the New Series Bond set forth in Section B of this Article I.

(b) Notwithstanding any other provision of this Subsection A.2 of this Article I or of Section 2.03 of the Original Indenture, except as contemplated by the provisions of paragraph (c) below, a 2021 Global Bond may be transferred, in whole but not in part and in the manner provided in Section 2.03 of the Original Indenture, only to a nominee of the Depositary for such 2021 Global Bond, or to the Depositary, or to a successor Depositary for such 2021 Global Bond selected or approved by the Company, or to a nominee of such successor Depositary.

(c) (1) If at any time the Depositary for a 2021 Global Bond notifies the Company that it is unwilling or unable to continue as the Depositary for such 2021 Global Bond or if at any time the Depositary for a 2021 Global Bond shall no longer be eligible or in good standing under any applicable statute or regulation, the Company shall appoint a successor Depositary with respect to such 2021 Global Bond. If a successor Depositary for such 2021 Global Bond is not appointed by the Company within 90 days after the Company receives such notice or becomes aware of such ineligibility, the Company will execute, and the Trustee, upon receipt of a Company order for the authentication and delivery of 2021 Bonds in the form of definitive certificates in exchange for such 2021 Global Bond, will authenticate and deliver, without service charge, 2021 Bonds in the form of definitive certificates of like tenor and terms in an aggregate principal amount equal to the principal amount of the 2021 Global Bond in exchange for such 2021 Global Bond. Such 2021 Bonds will be issued to and registered in the name of such person or persons as are specified by the Depositary.

(2) The Company may at any time and in its sole discretion determine that any 2021 Bonds issued or issuable in the form of one or more 2021 Global Bonds shall no longer be represented by such 2021 Global Bond or Bonds. In any such event the Company will execute, and the Trustee, upon receipt of a Company order for the authentication and delivery of 2021 Bonds in the form of definitive certificates in exchange in whole or in part for such 2021 Global Bond or Bonds, will authenticate and deliver, without service charge, to each person specified by the Depositary, 2021 Bonds in the form of definitive certificates of like tenor and terms in an aggregate principal amount equal to the principal amount of such 2021 Global Bond or the aggregate principal amount of such 2021 Global Bonds in exchange for such 2021 Global Bond or Bonds.

(3) If the Company so elects in an officer's certificate, the Depositary may surrender 2021 Bonds issued in the form of a 2021 Global Bond in exchange in whole or in part for 2021 Bonds in the form of definitive certificates of like tenor and terms on such terms as are acceptable to the Company and such Depositary. Thereupon the Company shall execute, and the Trustee shall authenticate and deliver, without service charge, (A) to each person specified by such Depositary a new 2021 Bond or Bonds of like tenor and terms and any authorized denomination as requested by such person in aggregate principal amount equal to and in exchange for such person's beneficial interest in the 2021 Global Bond; and (B) to such Depositary a new 2021 Global Bond of like tenor and terms and in an authorized denomination equal to the difference, if any, between the principal amount of the surrendered 2021 Global Bond and the aggregate principal amount of 2021 Bonds delivered to holders thereof.

(4) In any exchange provided for in any of the preceding three subparagraphs, the Company shall execute and the Trustee shall authenticate and deliver 2021 Bonds in the form of definitive certificates in authorized denominations. Upon the exchange of the entire principal amount of a 2021 Global Bond for 2021 Bonds in the form of definitive certificates, such 2021 Global Bond shall be canceled by the Trustee. Except as provided in the immediately preceding subparagraph, 2021 Bonds issued in exchange for a 2021 Global Bond pursuant to Subsection A.2 of this Article I shall be registered in such names and in such authorized denominations as the Depositary for such 2021 Global Bond, acting pursuant to instructions from its direct or indirect participants or otherwise, shall instruct the Trustee. Provided that the Company and the Trustee have so agreed, the Trustee shall deliver such 2021 Bonds to the persons in whose names the 2021 Bonds are so to be registered.

(5) Any endorsement of a 2021 Global Bond to reflect the principal amount thereof, or any increase or decrease in such principal amount, shall be made in such manner and by such person or persons as shall be specified in or pursuant to any applicable letter of representations or other arrangement entered into with, or procedures of, the Depositary with respect to such 2021 Global Bond or in the Company order delivered or to be delivered pursuant to Section 4.07 of the Original Indenture with respect thereto. Subject to the provisions of Section 4.07 of the Original Indenture, the Trustee shall deliver and redeliver any such 2021 Global Bond in the manner and upon instructions given by the person or persons specified in or pursuant to any applicable letter of representations or other arrangement entered into with, or procedures of, the Depositary with respect to such 2021 Global Bond or in any applicable Company order. If a Company order pursuant to Section 4.07 of the Original Indenture is so delivered, any instructions by the Company with respect to such 2021 Global Bond contained therein shall be in writing but need not be accompanied by or contained in an officer's certificate and need not be accompanied by an opinion of counsel.

(6) The Depositary or, if there be one, its nominee, shall be the holder of a 2021 Global Bond for all purposes under the Indenture and the 2021 Bonds and beneficial owners with respect to such 2021 Global Bond shall hold their interests pursuant to applicable procedures of such Depositary. The Company, the Trustee and any bond registrar shall be entitled to deal with such Depositary for all purposes of the Indenture relating to such 2021 Global Bond (including the payment of principal, the Redemption Price, if applicable, and interest and the giving of instructions or directions by or to the beneficial owners of such 2021 Global Bond as the sole holder of such 2021 Global Bond and shall have no obligations to the beneficial owners thereof

(including any direct or indirect participants in such Depositary)). None of the Company, the Trustee, any paying agent or bond registrar shall have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests of a beneficial owner in or pursuant to any applicable letter of representations or other arrangement entered into with, or procedures of, the Depositary with respect to such 2021 Global Bond or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

Section 3. August 18, 2011, shall be the date of the beginning of the first interest period for the 2021 Bonds. The first Interest Payment Date (as defined below) shall be February 15, 2012. The 2021 Bonds shall be dated as provided in Section 2.01 of the Original Indenture. The 2021 Bonds shall be payable on August 15, 2021, in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts, and shall bear interest, payable in like coin or currency, at the rate of 3.10% per annum, payable semiannually on February 15 and August 15 of each year (each an "Interest Payment Date") to the persons in whose names the 2021 Bonds are registered at the close of business on the tenth calendar day next preceding the Interest Payment Date (i.e., February 5 and August 5, respectively) (each a "Regular Record Date"), *provided, however,* that so long as the 2021 Bonds are registered in the name of DTC, its nominee or a successor depository, the Regular Record Date for interest payable on any Interest Payment Date shall be the close of business on the business day immediately preceding such Interest Payment Date (each subject to certain exceptions provided in this Supplemental Indenture and the Indenture), until maturity, according to the terms of the bonds or on prior redemption or by declaration or otherwise, and at the highest rate of interest borne by any of the bonds outstanding under the Indenture from such date of maturity until they shall be paid or payment thereof shall have been duly provided for. Principal of, and interest on, the 2021 Bonds and the Redemption Price, if applicable, shall be payable at the office or agency of the Company in the Borough of Manhattan, The City of New York; *provided, however,* that payment of interest may be made, at the option of the Company, by check mailed by the Company or its affiliate to the person entitled thereto at his registered address. If a due date for the payment of interest, principal or the Redemption Price, if applicable, falls on a day that is not a business day, then the payment will be made on the next succeeding business day, and no interest will accrue on the amounts payable for the period from and after the original due date and until the next business day. The term "business day" means any day other than a Saturday or Sunday or day on which banking institutions in the City of New York are required or authorized to close.

At any time on or after May 15, 2021, the 2021 Bonds may be redeemed at the option of the Company in whole at any time, or in part from time to time, at a redemption price equal to 100% of the principal amount of the 2021 Bonds being redeemed, plus in each case accrued and unpaid interest on the principal amount being redeemed to the redemption date. The 2021 Bonds may be redeemed at the option of the Company in whole at any time, or in part from time to time, prior to May 15, 2021, at a make-whole redemption price (the "Make-Whole Redemption Price" and, together with the redemption price referred to in the preceding sentence, each a "Redemption Price"). The Make-Whole Redemption Price shall be equal to the greater of (i) 100% of the principal amount of the 2021 Bonds being redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2021 Bonds being redeemed, discounted to the redemption date on a semiannual basis (assuming a 360-day year

consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 15 basis points, plus in each case accrued and unpaid interest on the principal amount being redeemed to the redemption date.

"Comparable Treasury Issue," means the United States Treasury security or securities selected by an Independent Investment Banker (as defined below) as having an actual or interpolated maturity comparable to the remaining term of the 2021 Bonds being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2021 Bonds.

"Comparable Treasury Price," means, with respect to any redemption date, the average of the Reference Treasury Dealer Quotations (as defined below) for such redemption date.

"Independent Investment Banker," means one of the Reference Treasury Dealer(s) (as defined below) selected by the Company.

"Reference Treasury Dealer," means Barclays Capital Inc., Citigroup Global Markets Inc. or Goldman, Sachs & Co., and their respective successors, and one additional primary U.S. Government securities dealer in The City of New York (each a "primary treasury dealer") selected by the Company. If any Reference Treasury Dealer shall cease to be a primary treasury dealer, the Company will substitute another primary treasury dealer for that dealer.

"Reference Treasury Dealer Quotations," means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Company, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Company by such Reference Treasury Dealer at 3:30 p.m. New York time on the third business day preceding such redemption date.

"Treasury Rate," means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to actual or interpolated maturity (on a day count basis) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

So long as the 2021 Bonds are registered in the name of DTC, its nominee or a successor depositary, if the Company elects to redeem less than all of the 2021 Bonds, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in the 2021 Bonds to be redeemed. At all other times, the Trustee shall draw by lot, in such manner as it deems appropriate, the particular 2021 Bonds, or portions of them, to be redeemed.

The 2021 Bonds shall also be redeemable, as a whole but not in part, at the Make-Whole Redemption Price in the event that (i) all the outstanding common stock of the Company shall be acquired by some governmental body or instrumentality and the Company elects to redeem all of the bonds of all series, the redemption date in any such event to be not more than one hundred twenty (120) days after the date on which all said stock is so acquired, or (ii) all, or substantially all, the mortgaged and pledged property constituting bondable property which at the time shall be subject to the lien of the Indenture as a first lien shall be released from the lien of the

Indenture pursuant to the provisions thereof, and available moneys in the hands of the Trustee, including any moneys deposited by the Company available for the purpose, are sufficient to redeem all the bonds of all series at the redemption prices (together with accrued interest to the date of redemption) specified therein applicable to the redemption thereof upon the happening of such event.

Notice of redemption shall be given by mail not less than 30 nor more than 90 days prior to the date fixed for redemption to the holders of 2021 Bonds to be redeemed (which, as long as the 2021 Bonds are held in the book-entry only system, will be the Depositary, its nominee or a successor depositary). On and after the date fixed for redemption (unless the Company defaults in the payment of the Redemption Price and interest accrued thereon to such date), interest on the 2021 Bonds or the portions of them so called for redemption shall cease to accrue. If the Company elects to redeem any 2021 Bonds, the Company will notify the Trustee of its election at least 45 days prior to the redemption date (or a shorter period acceptable to the Trustee) including in such notice, a reasonably detailed computation of the Redemption Price.

The 2021 Bonds of the several denominations are exchangeable for a like aggregate principal amount of other 2021 Bonds of other authorized denominations. Notwithstanding the provisions of Section 2.03 of the Original Indenture, for any exchange of the 2021 Bonds for other 2021 Bonds of different authorized denominations, or for any transfer of 2021 Bonds, the Company may require the payment of a sum sufficient to reimburse it for any tax or other governmental charge incident thereto only. The 2021 Bonds may be presented for transfer or exchange at the corporate trust office of the Trustee in New York, New York.

B. FORM OF THE NEW SERIES BONDS

The New Series Bonds shall be substantially in the following form, with such inclusions, omissions, and variations as the Board of Directors of the Company may determine in accordance with the provisions of the Indenture:

[FORM OF THE NEW SERIES BONDS]

[Insert applicable depositary legend or legends, which initially shall be the following:

THIS SECURITY IS A GLOBAL NOTE WITHIN THE MEANING OF THE INDENTURE HEREINAFTER REFERRED TO AND IS REGISTERED IN THE NAME OF A DEPOSITARY OR A NOMINEE THEREOF. THIS SECURITY MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SECURITY IN WHOLE OR IN PART MAY BE REGISTERED, IN THE NAME OF ANY PERSON OTHER THAN SUCH DEPOSITARY OR A NOMINEE THEREOF, EXCEPT IN THE LIMITED CIRCUMSTANCES DESCRIBED IN THE INDENTURE.

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY, A NEW YORK CORPORATION ("DTC"), TO FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC. OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE, OR PAYMENT, AND ANY CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR IN SUCH

OTHER NAME AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR TO SUCH OTHER ENTITY AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE, OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

THIS FIRST MORTGAGE BOND, ___% SERIES DUE 20__ MAY, UNDER CONDITIONS PROVIDED IN THE INDENTURE, BE EXCHANGED FOR FIRST MORTGAGE BONDS, ___% SERIES DUE 20__ IN THE FORM OF DEFINITIVE CERTIFICATES OF LIKE TENOR AND OF AN EQUAL AGGREGATE PRINCIPAL AMOUNT, IN AUTHORIZED DENOMINATIONS, REGISTERED IN THE NAMES OF SUCH PERSONS AS THE DEPOSITARY SHALL INSTRUCT THE TRUSTEE. ANY SUCH EXCHANGE SHALL BE MADE UPON RECEIPT BY THE TRUSTEE OF AN OFFICER'S CERTIFICATE THEREFOR AND A WRITTEN INSTRUCTION FROM THE DEPOSITARY SETTING FORTH THE NAME OR NAMES IN WHICH THE TRUSTEE IS TO REGISTER SUCH FIRST MORTGAGE BONDS, ___% SERIES DUE 20__ IN THE FORM OF DEFINITIVE CERTIFICATES.]

REGISTERED BOND **CUSIP No. _____**

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
(Incorporated under the laws of the State of Florida)

FIRST MORTGAGE BOND,
___% SERIES DUE 20__
DUE _____, 20__

No. _____ **$_____**

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC., a corporation of the State of Florida (hereinafter called the Company), for value received, hereby promises to pay to _____ or registered assigns, on _____ at the office or agency of the Company in the Borough of Manhattan, The City of New York, _____ Million Dollars ($___,000,000) in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts, and to pay interest thereon, semiannually on February 15 and August 15 of each year, commencing February 15, 2012, to the person in whose name this bond is registered at the close of business on the tenth calendar day next preceding the interest payment date (i.e., February 5 and August 5, respectively), *provided, however*, that so long as this bond is registered in the name of The Depository Trust Company, its nominee or a successor depository, the record date for interest payable on any interest payment date shall be the close of business on the business day immediately preceding such interest payment date (each subject to certain exceptions provided in the Mortgage hereinafter mentioned), at the rate of ___ per annum, at said office or agency in like coin or currency, from the date hereof until this bond shall mature, according to its terms or on prior redemption or by declaration or otherwise, and at the highest rate of interest borne by any of the bonds outstanding under the Mortgage hereinafter mentioned

from such date of maturity until this bond shall be paid or the payment hereof shall have been duly provided for; *provided, however*, that payment of interest may be made at the option of the Company by check mailed by the Company or its affiliate to the person entitled thereto at his registered address. If a due date for the payment of interest, principal, or the Redemption Price, if applicable, falls on a day that is not a business day, then the payment will be made on the next succeeding business day, and no interest will accrue on the amounts payable for the period from and after the original due date and until the next business day. The term "business day" means any day other than a Saturday or Sunday or day on which banking institutions in the City of New York are required or authorized to close.

Additional provisions of this bond are set forth on the reverse hereof and such provisions shall for all purposes have the same effect as though fully set forth at this place.

This bond shall not become valid or obligatory for any purpose until The Bank of New York Mellon, or its successor as Trustee under the Mortgage, shall have signed the certificate of authentication endorsed hereon.

IN WITNESS WHEREOF, FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC. has caused this bond to be signed in its name by its President or one of its Vice Presidents by his signature or a facsimile thereof, and its corporate seal, or a facsimile thereof, to be affixed hereto and attested by its Secretary or one of its Assistant Secretaries by his signature or a facsimile thereof.

Dated: August __, 2011

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

By: _____
Name:
Title:

[SEAL]

Attest:

_____
Name:
Title:

TRUSTEE'S AUTHENTICATION CERTIFICATE

This bond is one of the bonds, of the series herein designated, described or provided for in the within-mentioned Mortgage.

THE BANK OF NEW YORK MELLON

By: _____
Name:
Title:

[TEXT APPEARING ON REVERSE SIDE OF BOND]

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

FIRST MORTGAGE BOND
___% SERIES DUE 20__
DUE _____, 20__

This bond is one of an issue of bonds of the Company (herein referred to as the bonds), not limited in principal amount except as provided in the Mortgage hereinafter mentioned, issuable in series, which different series may mature at different times, may bear interest at different rates, and may otherwise vary as provided in the Mortgage hereinafter mentioned, and is one of a series known as its First Mortgage Bonds, ___% Series due 20__ (herein referred to as the "Bonds of this Series"), all bonds of all series issued and to be issued under and equally and ratably secured (except insofar as any sinking or analogous fund, established in accordance with the provisions of the Mortgage hereinafter mentioned, may afford additional security for the bonds of any particular series) by an Indenture dated as of January 1, 1944 (the "Original Indenture" and herein, together with all indentures supplemental thereto including the Fiftieth Supplemental Indenture dated as of August 1, 2011 (the "Fiftieth Supplemental Indenture") between the Company and The Bank of New York Mellon, as Trustee, called the "Mortgage"), to which reference is made for the nature and extent of the security, the rights of the holders of bonds and of the Company in respect thereof, the rights, duties and immunities of the Trustee, and the terms and conditions upon which the bonds are, and are to be, issued and secured. The Mortgage contains provisions permitting the holders of not less than seventy-five per centum (75%) in principal amount of all the bonds at the time outstanding, determined and evidenced as provided in the Mortgage, or in case the rights under the Mortgage of the holders of bonds of one or more, but less than all, of the series of bonds outstanding shall be affected, the holders of not less than seventy-five per centum (75%) in principal amount of the bonds at the time outstanding of all series affected, determined and evidenced as provided in the Mortgage, on behalf of the holders of all the bonds to waive any past default under the Mortgage and its consequences except a completed default, as defined in the Mortgage, in respect of the payment of the principal of or interest on any bond or default arising from the creation of any lien ranking prior to or equal with the lien of the Mortgage on any of the mortgaged and pledged property. The Mortgage also contains provisions permitting the Company and the Trustee, with the consent of the holders of not less than seventy-five per centum (75%) in principal amount of all the bonds at the time outstanding, determined and evidenced as provided in the Mortgage, or in case the

rights under the Mortgage of the holders of bonds of one or more, but less than all, of the series of bonds outstanding shall be affected, then with the consent of the holders of not less than seventy-five per centum (75%) in principal amount of the bonds at the time outstanding of all series affected, determined and evidenced as provided in the Mortgage, to execute supplemental indentures adding any provisions to or changing in any manner or eliminating any of the provisions of the Mortgage or modifying in any manner the rights of the holders of the bonds and coupons; *provided, however,* that no such supplemental indenture shall (i) extend the fixed maturity of any bonds, or reduce the rate or extend the time of payment of interest thereon, or reduce the principal amount thereof, without the express consent of the holder of each bond so affected, or (ii) reduce the aforesaid percentage of bonds, the holders of which are required to consent to any such supplemental indenture, without the consent of the holders of all bonds then outstanding, or (iii) permit the creation of any lien ranking prior to or equal with the lien of the Mortgage on any of the mortgaged and pledged property, or (iv) deprive the holder of any outstanding bond of the lien of the Mortgage on any of the mortgaged and pledged property. Any such waiver or consent by the registered holder of this bond (unless effectively revoked as provided in the Mortgage) shall be conclusive and binding upon such holder and upon all future holders of this bond, irrespective of whether or not any notation of such waiver or consent is made upon this bond. No reference herein to the Mortgage and no provision of this bond or of the Mortgage shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of and interest on this bond at the time and place and at the rate and in the coin or currency herein prescribed.

The Bonds of this Series are issuable in denominations of Two Thousand Dollars ($2,000) and any integral multiple of One Thousand Dollars ($1,000) above that amount and are exchangeable for a like aggregate principal amount of Bonds of this Series of other authorized denominations. This bond is transferable as prescribed in the Mortgage by the registered holder hereof in person, or by his duly authorized attorney, at the office or agency of the Company in said Borough of Manhattan, The City of New York, upon surrender and cancellation of this bond, and upon payment, if the Company shall require it, of the transfer charges prescribed in the Fiftieth Supplemental Indenture hereinabove referred to, and thereupon a new fully registered bond or bonds of authorized denominations of the same series and for the same aggregate principal amount will be issued to the transferee in exchange herefor as provided in the Mortgage. The Company and the Trustee, any paying agent and any bond registrar may deem and treat the person in whose name this bond is registered as the absolute owner hereof, whether or not this bond shall be overdue, for the purpose of receiving payment and for all other purposes and neither the Company nor the Trustee nor any paying agent nor any bond registrar shall be affected by any notice to the contrary.

At any time on or after May 15, 20__, the Bonds of this Series may be redeemed at the option of the Company in whole at any time, or in part from time to time, at a redemption price equal to 100% of the principal amount of the Bonds of this Series being redeemed, plus in each case accrued and unpaid interest on the principal amount being redeemed to the redemption date. The Bonds of this Series may be redeemed at the option of the Company in whole at any time, or in part from time to time, prior to May 15, 20__, at a make-whole redemption price (the "Make-Whole Redemption Price" and, together with the redemption price referred to in the preceding sentence, each a "Redemption Price"). The Make-Whole Redemption Price shall be equal to the greater of (i) 100% of the principal amount of the Bonds of this Series being redeemed or (ii) the

sum of the present values of the remaining scheduled payments of principal and interest on the Bonds of this Series being redeemed, discounted to the redemption date on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus ___ basis points, plus in each case accrued and unpaid interest on the principal amount being redeemed to the redemption date.

"Comparable Treasury Issue," means the United States Treasury security or securities selected by an Independent Investment Banker (as defined below) as having an actual or interpolated maturity comparable to the remaining term of the Bonds of this Series being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such Bonds of this Series.

"Comparable Treasury Price," means, with respect to any redemption date the average of the Reference Treasury Dealer Quotations (as defined below) for such redemption date.

"Independent Investment Banker," means one of the Reference Treasury Dealer(s) (as defined below) appointed by the Company.

"Reference Treasury Dealer," means Barclays Capital Inc., Citigroup Global Markets Inc. or Goldman, Sachs & Co., and their respective successors, and one additional primary U.S. Government securities dealer in The City of New York (each a "primary treasury dealer") selected by the Company. If any Reference Treasury Dealer shall cease to be a primary treasury dealer, the Company will substitute another primary treasury dealer for that dealer.

"Reference Treasury Dealer Quotations," means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Company, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Company by such Reference Treasury Dealer at 3:30 p.m. New York time on the third business day preceding such redemption date.

"Treasury Rate," means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to actual or interpolated maturity (on a day count basis) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

So long as the Bonds of this Series are registered in the name of DTC, its nominee or a successor depositary, if the Company elects to redeem less than all of the Bonds of this Series, DTC's practice is to determine by lot the amount of the interest of each Direct Participant of DTC in the Bonds of this Series to be redeemed. At all other times, the Trustee shall draw by lot, in such manner as it deems appropriate, the particular Bonds of this Series, or portions of them, to be redeemed.

The Bonds of this Series shall also be redeemable, as a whole but not in part, at the Make-Whole Redemption Price in the event that (i) all the outstanding common stock of the Company shall be acquired by some governmental body or instrumentality and the Company elects to redeem all of the bonds of all series, the redemption date in any such event to be not more than one hundred

twenty (120) days after the date on which all said stock is so acquired, or (ii) all or substantially all the mortgaged and pledged property constituting bondable property as defined in the Mortgage which at the time shall be subject to the lien of the Mortgage as a first lien shall be released from the lien of the Mortgage pursuant to the provisions thereof, and available moneys in the hands of The Bank of New York Mellon, or its successor as Trustee, including any moneys deposited by the Company available for the purpose, are sufficient to redeem all the bonds of all series at the redemption prices (together with accrued interest to the date of redemption) specified therein applicable to the redemption thereof upon the happening of such event.

Notice of redemption shall be given by mail not less than 30 nor more than 90 days prior to the date fixed for redemption to the holders of the Bonds of this Series to be redeemed (which, as long as the Bonds of this Series are held in the book-entry only system, will be the Depositary, its nominee or a successor depositary). On and after the date fixed for redemption (unless the Company defaults in the payment of the Redemption Price and interest accrued thereon to such date), interest on the Bonds of this Series or the portions of them so called for redemption shall cease to accrue. If the Company elects to redeem any Bonds of this Series, the Company will notify the Trustee of its election at least 45 days prior to the redemption date (or a shorter period acceptable to the Trustee) including in such notice, a reasonably detailed computation of the Redemption Price.

The Mortgage provides that if the Company shall deposit with The Bank of New York Mellon or its successor as Trustee in trust for the purpose funds sufficient to pay the principal of all the bonds of any series, or such of the bonds of any series as have been or are to be called for redemption (including any portions, constituting $1,000 or an integral multiple thereof, of fully registered bonds), and premium, if any, thereon, and all interest payable on such bonds (or portions) to the date on which they become due and payable at maturity or upon redemption or otherwise, and complies with the other provisions of the Mortgage in respect thereof, then from the date of such deposit such bonds (or portions) shall no longer be secured by the lien of the Mortgage.

The Mortgage provides that, upon any partial redemption of a fully registered bond, upon surrender thereof endorsed for transfer, new bonds of the same series and of authorized denominations in principal amount equal to the unredeemed portion of such fully registered bond will be delivered in exchange therefor.

The principal hereof may be declared or may become due prior to the express date of the maturity hereof on the conditions, in the manner and at the time set forth in the Mortgage, upon the occurrence of a completed default as in the Mortgage provided.

No recourse shall be had for the payment of the principal of, the Redemption Price, if applicable, or interest on this bond, or for any claim based hereon, or otherwise in respect hereof, or based on or in respect of the Mortgage or under or upon any obligation, covenant or agreement contained in the Mortgage, against any incorporator or any past, present or future subscriber to the capital stock, stockholder, officer or director, as such, of the Company or of any predecessor or successor corporation, either directly or through the Company or any predecessor or successor corporation under any present or future rule of law, statute or constitution or by the enforcement

of any assessment or otherwise, all such liability of incorporators, subscribers, stockholders, officers and directors, as such, being waived and released by the holder and owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Mortgage.

C. INTEREST ON THE NEW SERIES BONDS

Interest on any New Series Bond which is payable, and is punctually paid or duly provided for, on any Interest Payment Date shall be paid to the person in whose name that bond (or one or more predecessor bonds) is registered at the close of business on the Regular Record Date for such interest specified in the provisions of this Supplemental Indenture. Interest shall be computed on the basis of a 360-day year composed of twelve 30-day months.

Any interest on any New Series Bond which is payable, but is not punctually paid or duly provided for, on any Interest Payment Date (herein called "Defaulted Interest") shall forthwith cease to be payable to the registered holder on the relevant Regular Record Date solely by virtue of such holder having been such holder; and such Defaulted Interest may be paid by the Company, at its election in each case, as provided in Subsection A or B below:

A. The Company may elect to make payment of any Defaulted Interest on the New Series Bonds to the persons in whose names such bonds (or their respective predecessor bonds) are registered at the close of business on a special record date for the payment of such Defaulted Interest, which shall be fixed in the following manner (a "Special Record Date"). The Company shall notify the Trustee in writing of the amount of Defaulted Interest proposed to be paid on each bond and the date of the proposed payment (which date shall be such as will enable the Trustee to comply with the next sentence hereof), and at the same time the Company shall deposit with the Trustee an amount of money equal to the aggregate amount proposed to be paid in respect of such Defaulted Interest or shall make arrangements satisfactory to the Trustee for such deposit prior to the date of the proposed payment, such money when deposited to be held in trust for the benefit of the persons entitled to such Defaulted Interest as in this Subsection provided and not to be deemed part of the trust estate or trust moneys. Thereupon the Trustee shall fix a Special Record Date for the payment of such Defaulted Interest which shall be not more than 15 nor less than 10 days prior to the date of the proposed payment and not less than 10 days after the receipt by the Trustee of the notice of the proposed payment. The Trustee shall promptly notify the Company of such Special Record Date and, in the name and at the expense of the Company, shall cause notice of the proposed payment of such Defaulted Interest and the Special Record Date therefor to be mailed, first-class postage prepaid, to each holder of a bond of the New Series Bonds at the address as it appears in the bond register not less than 10 days prior to such Special Record Date. The Trustee may, in its discretion in the name and at the expense of the Company, cause a similar notice to be published at least once in a newspaper approved by the Company in each place of payment of the New Series Bonds, but such publication shall not be a condition precedent to the establishment of such Special Record Date. Notice of the proposed payment of such Defaulted Interest and the Special Record Date therefor having been mailed as aforesaid, such Defaulted Interest shall be paid to the persons in whose names the New Series Bonds (or their respective predecessor bonds)

are registered on such Special Record Date and shall no longer be payable pursuant to the following Subsection B.

B. The Company may make payment of any Defaulted Interest on the New Series Bonds in any other lawful manner not inconsistent with the requirements of any securities exchange on which such bonds may be listed and upon such notice as may be required by such exchange, if, after notice given by the Company to the Trustee of the proposed payment pursuant to this Subsection, such payment shall be deemed practicable by the Trustee.

Subject to the foregoing provisions of this Section, each New Series Bond delivered under this Supplemental Indenture upon transfer of or in exchange for or in lieu of any other New Series Bonds shall carry all the rights to interest accrued and unpaid, and to accrue, which were carried by such other bond and each such bond shall bear interest from such date, that neither gain nor loss in interest shall result from such transfer, exchange or substitution.

ARTICLE II

ADDITIONAL COVENANTS

The Company hereby covenants as follows:

Section 1. That it will, prior to or simultaneously with the initial authentication and delivery by the Trustee of the New Series Bonds under Section 4.03 of the Original Indenture, deliver to the Trustee the instruments required by said Section.

Section 2. That, so long as any of the New Series Bonds shall be outstanding, it will not declare or pay any dividends (except a dividend in its own common stock) upon its common stock, or make any other distribution (by way of purchase, or otherwise) to the holders thereof, except a payment or distribution out of net income of the Company subsequent to December 31, 1943; and that it will not permit any subsidiary of the Company to purchase any shares of common stock of the Company.

For the purpose of this Section, net income of the Company shall be determined by regarding as charges or credits to income, as the case may be, any and all charges or credits to earned surplus subsequent to December 31, 1943, representing adjustments on account of excessive or deficient accruals to income for taxes, and operating expenses shall include all proper charges for the maintenance and repairs of the property owned by the Company and appropriations out of income for the retirement or depreciation of the property used in its electric business in an amount of not less than the amount of the minimum provision for depreciation determined as provided in clause (5) of paragraph A of Section 1.05 of the Original Indenture.

ARTICLE III

SUNDRY PROVISIONS

Section 1. This Supplemental Indenture is executed and shall be construed as an indenture supplemental to the Original Indenture, and shall form a part thereof and all of the provisions

contained in the Original Indenture in respect to the rights, privileges, immunities, powers and duties of the Trustee shall be applicable in respect hereof as fully and with like effect as if set forth herein in full.

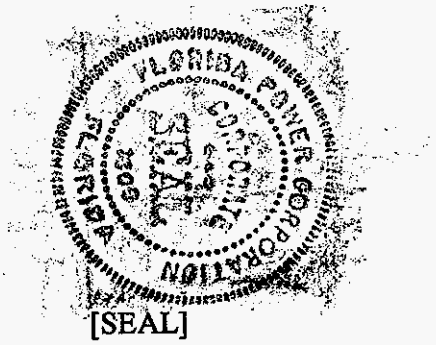
Section 2. This Supplemental Indenture may be simultaneously executed in any number of counterparts, and all of said counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

Section 3. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or of the due execution hereof by the Company or for or in respect of the recitals contained herein, all of which recitals are made by the Company solely.

Section 4. Although this Supplemental Indenture is dated for convenience and for purposes of reference as of August 1, 2011, the actual dates of execution by the Company and by the Trustee are as indicated by the respective acknowledgments hereto annexed.

[signature page follows]

IN WITNESS WHEREOF, FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC. has caused this Supplemental Indenture to be signed in its name and behalf by its Senior Vice President, and its corporate seal to be hereunto affixed and attested by its Assistant Secretary, and **THE BANK OF NEW YORK MELLON** has caused this Supplemental Indenture to be signed and sealed in its name and behalf by a Vice President, and its corporate seal to be attested by a Vice President, all as of the day and year first above written.



[SEAL]

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

By: _____
Mark F. Mulhern, Senior Vice President
299 First Avenue North
St. Petersburg, Florida 33701

Attest:

_____
Holly H. Wenger, Assistant Secretary
299 First Avenue North
St. Petersburg, Florida 33701

Signed, sealed and delivered by said
FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.

in the presence of:

_____
N. Manly Johnson III

_____
Sarah C. Nelson

[SEAL]

THE BANK OF NEW YORK MELLON

By: _____
Scott Klein, Vice President
101 Barclay Street
New York, New York 10286

Attest:

_____
Laurence J. O'Brien, Vice President
101 Barclay Street
New York, New York 10286

Signed, sealed and delivered by said
THE BANK OF NEW YORK MELLON

in the presence of:

_____
Sherma Thomas

_____
Jesse Espinola

STATE OF NORTH CAROLINA)

SS:

COUNTY OF WAKE)

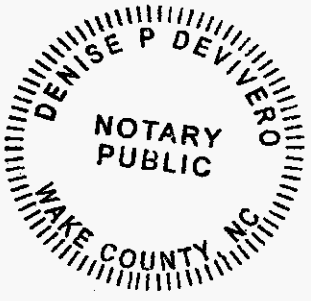
Before me, the undersigned, a notary public in and for the State and County aforesaid, an officer duly authorized to take acknowledgments of deeds and other instruments, personally appeared **Mark F. Mulhern, Senior Vice President** of **FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.**, a corporation, the corporate party of the first part in and to the above written instrument, and also personally appeared before me **Holly H. Wenger, Assistant Secretary** of the said corporation; such persons being severally personally known to me, who did take an oath and are known by me to be the same individuals who as such Senior Vice President and as such Assistant Secretary executed the above written instrument on behalf of said corporation; and he, the said Senior Vice President, acknowledged that as such Senior Vice President, he subscribed the said corporate name to said instrument on behalf and by authority of said corporation, and she, the said Assistant Secretary, acknowledged that she affixed the seal of said corporation to said instrument and attested the same by subscribing her name as Assistant Secretary of said corporation, by authority and on behalf of said corporation, and each of the two persons above named acknowledged that, being informed of the contents of said instrument, they, as such Senior Vice President and Assistant Secretary, delivered said instrument by authority and on behalf of said corporation and that all such acts were done freely and voluntarily and for the uses and purposes in said instrument set forth and that such instrument is the free act and deed of said corporation; and each of said persons further acknowledged and declared that he/she knows the seal of said corporation, and that the seal affixed to said instrument is the corporate seal of the corporation aforesaid.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal this 18th day of August, 2011 at Raleigh in the State and County aforesaid.

Denise P. deVivero

My commission expires: July 30, 2015

[NOTARIAL SEAL]



STATE OF NEW YORK)

SS:

COUNTY OF NEW YORK)

Before me, the undersigned, a notary public in and for the State of New York and County of Queens, an officer duly authorized to take acknowledgments of deeds and other instruments, personally appeared Scott Klein, Vice President (the "Executing Vice President") of **THE BANK OF NEW YORK MELLON**, a New York banking corporation, the corporate party of the second part in and to the above written instrument, and also personally appeared before me Laurence J. O'Brien, Vice President (the "Attesting Vice President") of the said corporation; said persons being severally personally known to me, who did take an oath and are known by me to be the same individuals who as such Executing Vice President and as such Attesting Vice President executed the above written instrument on behalf of said corporation; and he, the said Executing Vice President, acknowledged that as such Executing Vice President he subscribed the said corporate name to said instrument and affixed the seal of said corporation to said instrument on behalf and by authority of said corporation, and he, the said Attesting Vice President, acknowledged that he attested the same by subscribing his name as Vice President of said corporation, by authority and on behalf of said corporation, and each of the two persons above named acknowledged that, being informed of the contents of said instrument, they, as such Executing Vice President and Attesting Vice President, delivered said instrument by authority and on behalf of said corporation and that all such acts were done freely and voluntarily and for the uses and purposes in said instrument set forth and that such instrument is the free act and deed of said corporation, and each of said persons further acknowledged and declared that he knows the seal of said corporation, and that the seal affixed to said instrument is the corporate seal of the corporation aforesaid.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal this 15th day of August, 2011, at New York, in the State and County aforesaid.

Jacqueline Planas
Notary Public, State of New York
No. 01PL6240430
Qualified in New York County

JACQUELINE PLANAS
Notary Public, State of New York
No.01PL6240430
Qualified in New York County
Commission Expires April 28, 2015

My commission expires: April 28, 2015

[NOTARIAL SEAL]

EXHIBIT A

RECORDING INFORMATION

ORIGINAL INDENTURE dated January 1, 1944

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	02/25/44	121	172
Bay	10/20/47	59	18
Brevard	10/30/91	3157	3297
Citrus	02/25/44	18	1
Columbia	02/25/44	42	175
Dixie	02/25/44	3	127
Flagler	10/30/91	456	288
Franklin	02/25/44	0	83
Gadsden	02/26/44	A-6	175
Gilchrist	02/25/44	5	60
Gulf	02/26/44	6	193
Hamilton	02/25/44	42	69
Hardee	02/25/44	23	1
Hernando	02/25/44	90	1
Highlands	02/25/44	48	357
Hillsborough	02/25/44	662	105
Jackson	02/26/44	370	1
Jefferson	07/02/51	25	1
Lafayette	02/25/44	22	465
Lake	02/25/44	93	1
Leon	02/25/44	41	1
Levy	02/25/44	3	160
Liberty	02/25/44	"H"	116
Madison	07/02/51	61	86
Marion	02/25/44	103	1
Orange	02/25/44	297	375
Osceola	02/25/44	20	1
Pasco	02/25/44	39	449
Pinellas	02/26/44	566	1
Polk	02/25/44	666	305
Seminole	02/25/44	65	147
Sumter	02/25/44	25	1
Suwanee	02/25/44	58	425
Taylor	07/03/51	36	1
Volusia	02/25/44	135	156
Wakulla	02/25/44	14	1

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	02/25/44	24	1
Echols	02/25/44	A-1	300
Lowndes	02/25/44	5-0	1

SUPPLEMENTAL INDENTURE (First) dated July 1, 1946

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	11/12/46	166	1
Bay	10/20/47	59	1
Brevard	10/30/91	3157	3590
Citrus	11/12/46	17	362
Columbia	11/12/46	49	283
Dixie	11/14/46	3	357
Flagler	10/30/91	456	579
Franklin	11/13/46	"P"	80
Gadsden	11/13/46	A-9	148
Gilchrist	11/14/46	7	120
Gulf	11/13/46	10	313
Hamilton	11/12/46	40	371
Hardee	11/12/46	24	575
Hernando	11/14/46	99	201
Highlands	11/12/46	55	303
Hillsborough	11/06/46	95	375
Jackson	11/13/46	399	1
Jefferson	07/02/51	25	287
Lafayette	11/14/46	23	156
Lake	11/13/46	107	209
Leon	11/13/46	55	481
Levy	11/14/46	4	133
Liberty	11/13/46	"H"	420
Madison	07/02/51	61	373
Marion	11/12/46	110	1
Orange	11/12/46	338	379
Osceola	11/12/46	20	164
Pasco	11/14/46	44	169
Pinellas	11/06/46	632	161
Polk	11/12/46	744	511
Seminole	11/13/46	74	431
Sumter	11/13/46	25	467
Suwanee	11/12/46	63	316
Taylor	07/03/51	36	145
Volusia	11/13/46	158	203
Wakulla	11/13/36	14	299

SUPPLEMENTAL INDENTURE (Second) dated November 1, 1948

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	01/08/49	196	287
Bay	01/10/49	64	395
Brevard	10/30/91	3157	3607
Citrus	01/13/49	18	414
Columbia	01/08/49	55	493
Dixie	01/10/49	4	201
Flagler	10/30/91	456	601
Franklin	01/10/49	"Q"	1
Gadsden	01/10/49	A-13	157
Gilchrist	01/08/49	6	274
Gulf	01/10/49	13	74
Hamilton	01/10/49	44	1
Hardee	01/08/49	28	110
Hernando	01/08/49	109	448
Highlands	01/08/49	61	398
Hillsborough	01/13/49	810	452
Jackson	01/10/49	400	563
Jefferson	07/02/51	25	320
Lafayette	01/10/49	25	210
Lake	01/08/49	119	555
Leon	01/10/49	82	303
Levy	01/08/49	5	242
Liberty	01/08/49	"H"	587
Madison	07/02/51	61	407
Marion	01/11/49	122	172
Orange	01/08/49	388	604
Osceola	01/08/49	25	104
Pasco	01/08/49	47	549
Pinellas	01/05/49	716	11
Polk	01/07/49	807	411
Seminole	01/06/49	84	389
Sumter	01/08/49	28	41
Suwanee	01/08/49	69	150
Taylor	07/03/51	36	162
Volusia	01/06/49	192	167
Wakulla	01/10/49	16	1

SUPPLEMENTAL INDENTURE (Third) dated July 1, 1951

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/02/51	234	340
Bay	08/03/51	93	155
Brevard	10/30/91	3157	3630
Citrus	07/30/51	20	251
Columbia	08/02/51	66	503
Dixie	08/02/51	5	271
Flagler	10/30/91	456	624
Franklin	08/03/51	"Q"	522
Gadsden	08/03/51	A-19	271
Gilchrist	08/02/51	7	422
Gulf	08/03/51	16	59
Hamilton	08/03/51	51	347
Hardee	08/02/51	32	1
Hernando	08/02/51	118	537
Highlands	08/02/51	69	344
Hillsborough	08/02/51	927	174
Jefferson	08/03/51	25	359
Lafayette	08/03/51	27	305
Lake	07/31/51	139	323
Leon	08/02/51	113	465
Levy	08/02/51	7	211
Liberty	07/25/51	1	232
Madison	08/07/51	62	1
Marion	08/02/51	142	143
Orange	08/07/51	460	60
Osceola	08/02/51	31	385
Pasco	08/10/51	56	1
Pinellas	08/02/51	847	301
Polk	08/01/51	899	539
Seminole	08/07/51	100	403
Sumter	08/02/51	32	345
Suwanee	08/02/51	76	413
Taylor	08/07/51	36	182
Volusia	08/07/51	245	393
Wakulla	08/03/51	17	259

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	08/08/51	35	566
Echols	08/02/51	A-3	521
Lowndes	08/04/51	7-E	188

FOURTH SUPPLEMENTAL INDENTURE November 1, 1952

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/31/52	256	288
Bay	01/01/53	104	571
Brevard	10/30/91	3157	3663
Citrus	12/31/52	22	321
Columbia	12/31/52	72	521
Dixie	12/31/52	6	135
Flagler	10/31/91	456	657
Franklin	12/31/52	R	477
Gadsden	12/31/52	A-22	511
Gilchrist	12/31/52	9	124
Gulf	01/02/53	17	7
Hamilton	12/31/52	54	293
Hardee	12/31/52	33	433
Hernando	12/31/52	125	361
Highlands	01/02/53	74	131
Hillsborough	12/29/52	993	545
Jefferson	12/31/52	27	1
Lafayette	12/31/52	28	445
Lake	01/02/53	150	343
Leon	12/31/52	130	1
Levy	12/31/52	8	362
Liberty	01/09/53	1	462
Madison	01/02/53	65	134
Marion	01/02/53	153	434
Orange	12/31/52	505	358
Osceola	12/31/52	36	145
Pasco	01/02/53	61	563
Pinellas	12/29/52	926	561
Polk	01/12/53	974	177
Seminole	01/02/53	111	41
Sumter	12/31/52	35	441
Suwanee	01/02/53	82	27
Taylor	12/31/52	37	325
Volusia	01/10/53	278	107
Wakulla	01/02/53	18	383

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	01/01/53	39	95
Echols	01/01/53	A-4	110
Lowndes	12/31/52	7-0	540

FIFTH SUPPLEMENTAL INDENTURE November 1, 1953

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/29/53	271	24
Bay	01/01/54	115	505
Brevard	10/30/91	3157	3690
Citrus	12/28/53	2	73
Columbia	12/28/53	7	3
Dixie	12/23/53	6	466
Flagler	10/30/91	456	684
Franklin	12/28/53	1	447
Gadsden	12/24/53	A-26	251
Gilchrist	12/23/53	9	317
Gulf	12/28/53	11	229
Hamilton	12/28/53	58	220
Hardee	12/23/53	35	518
Hernando	12/23/53	130	409
Highlands	12/29/53	78	1
Hillsborough	01/04/54	1050	229
Jefferson	12/29/53	28	91
Lafayette	12/24/53	30	16
Lake	12/23/53	160	189
Leon	12/23/53	144	268
Levy	12/23/53	9	368
Liberty	01/06/54	J	40
Madison	12/26/53	67	381
Marion	12/28/53	168	179
Orange	12/24/53	541	253
Osceola	12/24/53	39	42
Pasco	12/23/53	67	1
Pinellas	12/22/53	988	333
Polk	01/05/54	1021	473
Seminole	12/29/53	118	535
Sumter	12/28/53	37	466
Suwanee	12/28/53	85	346
Taylor	12/24/53	43	225
Volusia	12/24/53	303	454
Wakulla	12/30/53	19	380

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	01/15/54	39	437
Echols	01/15/54	A-4	418
Lowndes	12/29/53	7-X	235

SIXTH SUPPLEMENTAL INDENTURE dated July 1, 1954

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	11/19/54	286	129
Bay	11/22/54	125	502
Brevard	10/30/91	3157	3719
Citrus	11/19/54	9	525
Columbia	11/20/54	17	479
Dixie	11/19/54	7	299
Flagler	10/30/91	456	713
Franklin	11/19/54	5	465
Gadsden	11/20/54	A-29	411
Gilchrist	11/19/54	9	530
Gulf	11/22/54	19	284
Hamilton	11/22/54	59	425
Hardee	11/19/54	37	307
Hernando	11/19/54	7	335
Highlands	11/19/54	82	403
Hillsborough	11/26/54	1116	164
Jefferson	11/19/54	29	17
Lafayette	11/19/54	31	138
Lake	11/19/54	170	225
Leon	11/19/54	159	209
Levy	11/19/54	10	523
Liberty	11/30/54	"J"	215
Madison	11/20/54	69	483
Marion	11/20/54	181	573
Orange	11/23/54	578	123
Osceola	11/20/54	42	216
Pasco	11/22/54	15	568
Pinellas	11/18/54	1046	507
Polk	11/23/54	1068	22
Seminole	11/19/54	28	374
Sumter	11/30/54	40	81
Suwanee	11/23/54	89	1
Taylor	11/20/54	45	377
Volusia	11/23/54	327	538
Wakulla	11/19/54	20	445

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	11/20/54	55	385
Echols	11/20/54	5	86
Lowndes	11/20/54	3	387

SEVENTH SUPPLEMENTAL INDENTURE dated July 1, 1956

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/27/56	320	309
Bay	07/27/56	145	395
Brevard	10/30/91	3157	3746
Citrus	07/25/56	28	403
Columbia	07/26/56	38	279
Dixie	07/30/56	9	1
Flagler	10/30/91	456	740
Franklin	07/27/56	16	392
Gadsden	07/26/56	A-36	100
Gilchrist	07/31/56	11	289
Gulf	08/02/56	23	475
Hamilton	07/27/56	11	79
Hardee	07/31/56	43	1
Hernando	07/26/56	21	88
Highlands	07/31/56	11	571
Hillsborough	08/06/56	1260	125
Jefferson	07/25/56	30	295
Lafayette	07/25/56	33	117
Lake	07/26/56	189	613
Leon	07/25/56	190	301
Levy	07/30/56	14	13
Liberty	07/31/56	"J"	531
Madison	07/26/56	74	12
Marion	07/26/56	208	223
Orange	07/27/56	126	165
Osceola	07/26/56	49	1
Pasco	08/02/56	51	353
Pinellas	07/24/56	1168	481
Polk	08/20/56	1180	30
Seminole	07/27/56	90	5
Sumter	08/02/56	43	523
Suwanee	07/26/56	96	67
Taylor	07/25/56	52	451
Volusia	07/26/56	384	195
Wakulla	07/25/56	22	281

STATE OF GEORGIA

County	Date of Recordation	Book	Page
Cook	07/26/56	48	36
Echols	07/26/56	5	401
Lowndes	07/25/56	22	419

EIGHTH SUPPLEMENTAL INDENTURE dated July 1, 1958

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/23/58	20	227
Bay	08/05/58	170	295
Brevard	10/30/91	3157	3785
Citrus	07/24/58	55	336
Columbia	07/23/58	66	365
Dixie	07/22/58	11	166
Flagler	10/30/91	456	779
Franklin	07/22/58	29	248
Gadsden	07/23/58	9	48
Gilchrist	07/22/58	12	341
Gulf	07/24/58	29	40
Hamilton	07/22/58	23	1
Hardee	07/22/58	49	451
Hernando	07/25/58	39	358
Highlands	07/29/58	50	514
Hillsborough	07/29/58	111	108
Jefferson	07/23/58	33	19
Lafayette	07/23/58	35	120
Lake	07/31/58	56	297
Leon	07/23/58	216	129
Levy	07/22/58	18	63
Liberty	07/24/58	"K"	413
Madison	07/23/58	78	310
Marion	07/29/58	237	447
Orange	07/23/58	403	300
Osceola	07/23/58	26	462
Pasco	07/25/58	96	455
Pinellas	07/24/58	381	683
Polk	07/24/58	165	452
Seminole	07/23/58	178	26
Sumter	08/01/58	5	66
Suwanee	07/23/58	102	360
Taylor	07/22/58	4	254
Volusia	07/23/58	129	244
Wakulla	07/25/58	24	375

NINTH SUPPLEMENTAL INDENTURE dated October 1, 1960

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	11/23/60	119	158
Bay	11/25/60	28	411
Brevard	10/30/91	3157	3822
Citrus	12/01/60	93	370
Columbia	11/17/60	105	133
Dixie	11/16/60	13	331
Flagler	10/30/91	456	816
Franklin	11/17/60	49	375
Gadsden	11/17/60	29	655
Gilchrist	11/16/60	1	473
Gulf	11/21/60	5	409
Hamilton	11/18/60	37	171
Hardee	11/17/60	60	76
Hernando	11/16/60	65	688
Highlands	11/18/60	108	421
Hillsborough	11/23/60	629	675
Jefferson	11/18/60	8	290
Lafayette	11/16/60	38	185
Lake	11/21/60	141	619
Leon	11/23/60	254	479
Levy	11/16/60	23	537
Liberty	11/17/60	"M"	525
Madison	11/22/60	11	153
Marion	11/18/60	54	420
Orange	11/22/60	817	569
Osceola	11/16/60	68	410
Pasco	11/21/60	158	530
Pinellas	11/16/60	1036	239
Polk	11/18/60	440	179
Seminole	11/21/60	332	203
Sumter	11/30/60	25	318
Suwanee	11/17/60	111	282
Taylor	11/18/60	21	626
Volusia	11/21/60	330	281
Wakulla	11/21/60	28	185

TENTH SUPPLEMENTAL INDENTURE dated May 1, 1962

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	06/07/62	188	123
Bay	06/15/62	70	173
Brevard	10/30/91	3157	3858
Citrus	06/08/62	120	221
Columbia	06/05/62	130	187
Dixie	06/05/62	15	36
Flagler	10/30/91	456	852
Franklin	06/06/62	58	333
Gadsden	06/05/62	45	493
Gilchrist	06/05/62	7	261
Gulf	06/06/62	14	147
Hamilton	06/05/62	46	407
Hardee	06/05/62	16	449
Hernando	06/05/62	82	326
Highlands	06/11/62	148	617
Hillsborough	0611/62	949	738
Jefferson	06/05/62	13	606
Lafayette	06/08/62	39	385
Lake	06/06/62	204	1
Leon	06/11/62	48	49
Levy	06/05/62	27	574
Liberty	06/06/62	0	214
Madison	06/05/62	20	76
Marion	06/15/62	112	412
Orange	06/06/62	1060	464
Osceola	06/05/62	90	389
Pasco	06/08/62	202	457
Pinellas	06/01/62	1438	571
Polk	06/14/62	605	696
Seminole	06/13/62	408	102
Sumter	06/13/62	40	85
Suwanee	06/05/62	116	273
Taylor	06/05/62	34	330
Volusia	06/20/62	456	46
Wakulla	06/11/62	31	349

ELEVENTH SUPPLEMENTAL INDENTURE dated April 1, 1965

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	05/21/65	324	610
Bay	05/28/65	158	231
Brevard	10/30/91	3157	3894
Citrus	05/13/65	179	485
Columbia	05/17/65	184	314
Dixie	05/13/65	6	485
Flagler	10/30/91	456	888
Franklin	05/19/65	72	497
Gadsden	05/18/65	73	410
Gilchrist	05/13/65	17	11
Gulf	05/18/65	24	717
Hamilton	05/13/65	63	327
Hardee	05/13/65	47	377
Hernando	05/13/65	112	236
Highlands	05/21/65	232	421
Hillsborough	05/12/65	1448	57
Jefferson	05/14/65	23	198
Lafayette	05/13/65	1	687
Lake	05/19/65	287	74
Leon	05/21/65	178	48
Levy	05/21/65	34	519
Liberty	05/14/65	6	1
Madison	05/14/65	34	399
Marion	05/24/65	228	528
Orange	05/25/65	1445	830
Osceola	05/18/65	132	351
Pasco	05/13/65	291	437
Pinellas	05/12/65	2154	77
Polk	05/17/65	929	371
Seminole	05/19/65	535	241
Sumter	05/14/65	68	83
Suwanee	05/17/65	24	673
Taylor	05/17/65	56	129
Volusia	05/19/65	708	531
Wakulla	05/17/65	8	6

TWELFTH SUPPLEMENTAL INDENTURE dated November 1, 1965

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/10/65	355	229
Bay	12/20/65	174	619
Brevard	10/30/91	3157	3931
Citrus	12/22/65	192	309
Columbia	12/10/65	194	338
Dixie	12/10/65	9	42
Flagler	10/30/91	456	925
Franklin	12/13/65	76	249
Gadsden	12/10/65	78	606
Gilchrist	12/10/65	19	447
Gulf	12/10/65	26	692
Hamilton	12/10/65	66	303
Hardee	12/10/65	53	426
Hernando	12/13/65	118	441
Highlands	12/20/65	248	20
Hillsborough	12/17/65	1548	603
Jefferson	12/10/65	24	595
Lafayette	12/10/65	2	671
Lake	12/20/65	301	528
Leon	12/20/65	205	170
Levy	12/20/65	36	184
Liberty	12/10/65	6	477
Madison	12/11/65	36	806
Marion	12/27/65	254	153
Orange	12/10/65	1499	785
Osceola	12/10/65	140	445
Pasco	12/13/65	312	19
Pinellas	12/09/65	2283	186
Polk	12/20/65	984	641
Seminole	12/22/65	559	591
Sumter	12/14/65	73	283
Suwanee	12/14/65	30	218
Taylor	12/10/65	59	361
Volusia	12/10/65	755	174
Wakulla	12/20/65	9	390

THIRTEENTH SUPPLEMENTAL INDENTURE dated August 1, 1967

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/22/67	458	347
Bay	08/28/67	223	457
Brevard	10/30/91	3157	3964
Citrus	08/28/67	218	756
Columbia	08/22/67	225	304
Dixie	08/22/67	15	367
Flagler	10/30/91	456	962
Franklin	08/28/67	83	556
Gadsden	08/23/67	96	29
Gilchrist	08/22/67	25	131
Gulf	08/22/67	33	618
Hamilton	08/23/67	76	465
Hardee	08/22/67	71	366
Hernando	08/28/67	137	646
Highlands	08/30/67	288	585
Hillsborough	08/28/67	1795	635
Jefferson	08/23/67	30	662
Lafayette	08/22/67	5	694
Lake	08/25/67	342	196
Leon	08/30/67	280	594
Levy	08/28/67	41	262
Liberty	08/23/67	10	90
Madison	08/23/67	44	606
Marion	09/01/67	324	444
Orange	08/24/67	1660	421
Osceola	08/22/67	164	335
Pasco	08/28/67	370	728
Pinellas	08/21/67	2659	498
Polk	09/06/67	1108	900
Seminole	08/31/67	628	506
Sumter	09/06/67	87	602
Suwanee	08/23/67	47	228
Taylor	08/24/67	67	782
Volusia	08/24/67	964	254
Wakulla	08/31/67	14	755

FOURTEENTH SUPPLEMENTAL INDENTURE dated November 1, 1968

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/06/68	543	198
Bay	12/18/68	262	487
Brevard	10/30/91	3157	3984
Citrus	12/09/68	239	487
Columbia	12/09/68	242	397
Dixie	12/09/68	20	109
Flagler	10/30/91	456	983
Franklin	12/06/68	88	538
Gadsden	12/12/68	110	7
Gilchrist	12/06/68	29	281
Gulf	12/09/68	38	359
Hamilton	12/06/68	82	245
Hardee	12/06/68	83	221
Hernando	12/09/68	164	395
Highlands	12/11/68	319	390
Hillsborough	12/19/68	1977	890
Jefferson	12/09/68	35	32
Lafayette	12/06/68	9	170
Lake	12/06/68	371	438
Leon	12/19/68	342	572
Levy	12/09/68	44	215
Liberty	12/09/68	12	41
Madison	12/09/68	49	627
Marion	12/20/68	375	12
Orange	12/06/68	1785	837
Osceola	12/06/68	183	688
Pasco	12/06/68	423	607
Pinellas	12/06/68	2964	580
Polk	12/10/68	1193	854
Seminole	12/18/68	695	638
Sumter	01/02/69	98	509
Suwanee	12/06/68	60	50
Taylor	12/09/68	73	494
Volusia	12/09/68	1060	466
Wakulla	12/19/68	18	593

***FIFTEENTH SUPPLEMENTAL INDENTURE* dated August 1, 1969**

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/26/69	592	206
Bay	09/03/69	283	513
Brevard	10/30/91	3157	4002
Citrus	08/26/69	251	437
Columbia	09/05/69	251	586
Dixie	08/26/69	21	705
Flagler	10/30/91	456	1001
Franklin	08/26/69	92	363
Gadsden	08/26/69	116	723
Gilchrist	09/04/69	31	539
Gulf	08/26/69	41	23
Hamilton	08/26/69	85	292
Hardee	08/26/69	91	19
Hernando	09/03/69	191	745
Highlands	09/05/69	339	90
Hillsborough	09/03/69	2073	501
Jefferson	08/26/69	37	193
Lafayette	08/26/69	12	235
Lake	09/11/69	389	148
Leon	09/05/69	377	548
Levy	08/26/69	6	348
Liberty	08/29/69	12	680
Madison	08/26/69	52	263
Marion	09/08/69	399	668
Orange	08/27/69	1867	156
Osceola	09/03/69	192	726
Pasco	08/26/69	459	315
Pinellas	08/26/69	3149	131
Polk	09/04/69	1241	971
Seminole	09/05/69	740	500
Sumter	09/05/69	104	504
Suwanee	08/26/69	66	489
Taylor	08/26/69	77	44
Volusia	08/26/69	1123	577
Wakulla	09/05/69	21	231

SIXTEENTH SUPPLEMENTAL INDENTURE dated February 1, 1970

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	03/13/70	625	297
Bay	03/23/70	298	539
Brevard	10/30/91	3157	4019
Citrus	03/16/70	261	729
Columbia	03/13/70	257	622
Dixie	03/13/70	23	107
Flagler	10/30/91	456	1019
Franklin	03/13/70	94	507
Gadsden	03/13/70	121	571
Gilchrist	03/20/70	33	449
Gulf	03/16/70	43	244
Hamilton	03/14/70	87	291
Hardee	03/16/70	97	225
Hernando	03/20/70	212	536
Highlands	03/20/70	352	25
Hillsborough	03/20/70	2146	824
Jefferson	03/13/70	38	643
Lafayette	03/16/70	14	42
Lake	03/13/70	400	545
Leon	04/02/70	406	203
Levy	03/20/70	11	150
Liberty	03/13/70	13	494
Madison	03/13/70	54	152
Marion	03/20/70	419	113
Orange	03/20/70	1927	853
Osceola	03/13/70	199	282
Pasco	03/13/70	487	207
Pinellas	03/23/70	3294	582
Polk	03/27/70	1278	4
Seminole	03/20/70	771	384
Sumter	03/27/70	109	1
Suwanee	03/13/70	71	61
Taylor	03/16/70	79	282
Volusia	03/13/70	1183	353
Wakulla	03/24/70	23	36

SEVENTEENTH SUPPLEMENTAL INDENTURE dated November 1, 1970

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/15/70	678	70
	01/08/71	682	405B
Bay	01/11/71	321	565
Brevard	10/30/91	3157	4030
Citrus	01/07/71	277	324
Columbia	12/16/70	266	25
	01/07/71	266	351
Dixie	01/07/71	25	246
Flagler	10/30/91	456	1030
Franklin	12/15/70	98	171
	01/18/71	98	472
Gadsden	01/07/71	128	705
Gilchrist	01/13/71	36	5
Gulf	12/16/70	46	132
Hamilton	12/16/70	90	201
	01/08/71	90	325
Hardee	12/16/70	106	109
	01/07/71	107	15
Hernando	12/16/70	246	299
	01/13/71	252	715
Highlands	01/11/71	372	79
Hillsborough	01/11/71	2261	308
Jefferson	12/16/70	41	467
Lafayette	01/06/71	16	144
Lake	01/12/71	421	742
Leon	01/14/71	449	244
Levy	01/11/71	18	65
Liberty	12/16/70	14	535
Madison	01/07/71	56	911
Marion	01/11/71	449	33
Orange	01/11/71	2021	24
Osceola	01/29/71	212	353
Pasco	01/08/71	524	86
Pinellas	01/14/71	3467	449
Polk	01/14/71	1331	880
Seminole	01/11/71	819	223
Sumter	01/11/71	115	308
Suwanee	12/17/70	77	82
Taylor	12/17/70	83	53
Volusia	01/11/71	1257	142
Wakulla	01/12/71	26	175

EIGHTEENTH SUPPLEMENTAL INDENTURE dated October 1, 1971

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	11/17/71	755	116
Bay	11/09/71	351	33
Brevard	10/30/91	3157	4062
Citrus	11/16/71	296	490
Columbia	11/15/71	278	597
Dixie	11/09/71	31	23
Flagler	10/30/91	456	1062
Franklin	11/09/71	103	278
Gadsden	11/10/71	138	360
Gilchrist	11/16/71	39	92
Gulf	11/11/71	49	107
Hamilton	11/09/71	93	538
Hardee	11/09/71	119	63
Hernando	11/17/71	280	1
Highlands	11/16/71	393	578
Hillsborough	11/17/71	2393	263
Jefferson	11/11/71	45	135
Lafayette	11/09/71	19	91
Lake	11/16/71	447	834
Leon	11/12/71	496	190
Levy	11/16/71	26	748
Liberty	11/10/71	16	108
Madison	11/11/71	61	220
Marion	11/16/71	487	239
Orange	11/18/71	2144	179
Osceola	11/10/71	229	360
Pasco	11/12/71	569	344
Pinellas	11/09/71	3659	630
Polk	11/16/71	1400	1
Seminole	11/16/71	892	460
Sumter	11/09/71	123	457
Suwanee	11/12/71	86	28
Taylor	11/09/71	87	706
Volusia	11/09/71	1352	118
Wakulla	11/16/71	30	218

NINETEENTH SUPPLEMENTAL INDENTURE dated June 1, 1971

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/31/72	797	81
Bay	07/31/72	378	483
Brevard	10/30/91	3157	4079
Citrus	08/01/72	314	557
Columbia	07/31/72	290	418
Dixie	07/31/72	35	44
Flagler	10/30/91	456	1079
Franklin	07/31/72	107	442
Gadsden	07/31/72	147	296
Gilchrist	07/31/72	41	148
Gulf	07/31/72	51	371
Hamilton	07/31/72	96	573
Hardee	07/31/72	130	35
Hernando	07/31/72	295	702
Highlands	07/31/72	409	578
Hillsborough	07/31/72	2518	15
Jefferson	07/31/72	48	389
Lafayette	08/04/72	22	70
Lake	08/02/72	474	134
Leon	08/02/72	537	763
Levy	08/02/72	35	5
Liberty	08/03/72	17	319
Madison	08/03/72	65	120
Marion	08/02/72	521	427
Orange	08/03/72	2259	950
Osceola	08/02/72	245	626
Pasco	08/03/72	619	487
Pinellas	08/02/72	3846	454
Polk	08/02/72	1467	276
Seminole	08/03/72	948	1035
Sumter	08/02/72	131	348
Suwanee	08/02/72	93	785
Taylor	08/03/72	92	198
Volusia	08/02/72	1456	420
Wakulla	08/03/72	33	147

TWENTIETH SUPPLEMENTAL INDENTURE dated November 1, 1972

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	01/22/73	818	709
Bay	01/22/73	400	226
Brevard	10/30/91	3157	4096
Citrus	01/22/73	328	152
Columbia	01/22/73	298	244
Dixie	01/22/73	38	92
Flagler	10/30/91	456	1096
Franklin	01/22/73	110	446
Gadsden	01/22/73	154	117
Gilchrist	01/2273	42	685
Gulf	01/22/73	52	813
Hamilton	01/22/73	99	270
Hardee	01/22/73	138	88
Hernando	01/22/73	306	325
Highlands	01/22/73	422	5
Hillsborough	01/22/73	2612	659
Jefferson	01/23/73	50	632
Lafayette	01/22/73	23	338
Lake	01/22/73	492	696
Leon	01/25/73	567	238
Levy	01/22/73	40	755
Liberty	01/23/73	18	51
Madison	01/23/73	67	413
Marion	01/22/73	546	125
Orange	01/22/73	2345	569
Osceola	01/24/73	256	564
Pasco	01/22/73	654	281
Pinellas	01/23/73	3980	788
Polk	01/24/73	1514	854
Seminole	01/22/73	136	696
Sumter	01/22/73	136	696
Suwanee	01/22/73	98	583
Taylor	01/22/73	95	99
Volusia	01/22/73	1533	327
Wakulla	01/26/73	35	266

TWENTY-FIRST SUPPLEMENTAL INDENTURE dated June 1, 1973

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/30/73	850	668
Bay	08/30/73	431	401
Brevard	10/30/91	3157	4126
Citrus	08/31/73	349	609
Columbia	08/30/73	309	245
Dixie	08/30/73	41	473
Flagler	10/30/91	456	1126
Franklin	08/31/73	115	120
Gadsden	08/31/73	164	90
Gilchrist	08/31/73	45	387
Gulf	09/04/73	54	736
Hamilton	09/04/73	104	250
Hardee	08/31/73	149	295
Hernando	08/31/73	321	479
Highlands	08/31/73	442	961
Hillsborough	08/31/73	2740	278
Jefferson	08/31/73	54	591
Lafayette	09/07/73	26	73
Lake	08/31/73	520	70
Leon	09/06/73	609	543
Levy	09/05/73	50	741
Liberty	08/31/73	19	111
Madison	08/31/73	71	22
Marion	09/04/73	585	491
Orange	09/07/73	2448	1009
Osceola	09/06/73	272	204
Pasco	09/04/73	707	613
Pinellas	08/31/73	4073	767
Polk	08/31/73	1550	1341
Seminole	09/04/73	993	0048
Sumter	08/31/73	144	265
Suwanee	09/04/73	106	192
Taylor	08/31/73	99	444
Volusia	08/31/73	1647	440
Wakulla	08/31/73	38	458

TWENTY-SECOND SUPPLEMENTAL INDENTURE dated December 1, 1973

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	02/28/74	876	74
Bay	02/28/74	457	572
Brevard	10/30/91	3157	4155
Citrus	03/18/74	365	200
Columbia	03/01/74	319	179
Dixie	02/28/74	44	149
Flagler	10/30/91	456	1155
Franklin	03/01/74	119	14
Gadsden	03/01/74	171	264
Gilchrist	02/28/74	48	25
Gulf	03/01/74	56	427
Hamilton	03/01/74	109	89
Hardee	02/28/74	158	140
Hernando	02/28/74	333	455
Highlands	02/28/74	458	394
Hillsborough	02/28/74	2842	642
Jefferson	03/01/74	58	5
Lafayette	03/01/74	28	34
Lake	03/04/74	540	77
Leon	03/01/74	638	672
Levy	02/28/74	57	769
Liberty	03/01/74	20	54
Madison	03/01/74	73	545
Marion	02/28/74	617	19
Orange	02/28/74	2504	1707
Osceola	03/01/74	284	344
Pasco	03/01/74	739	1360
Pinellas	02/28/74	4141	1397
Polk	02/28/74	1578	1983
Seminole	03/04/74	1010	1601
Sumter	03/01/74	150	278
Suwanee	03/04/74	111	766
Taylor	03/04/74	102	694
Volusia	03/04/74	1712	645
Wakulla	03/05/74	40	626

TWENTY-THIRD SUPPLEMENTAL INDENTURE dated October 1, 1976

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	11/29/76	1035	716
Bay	11/29/76	600	687
Brevard	10/30/91	3157	4184
Citrus	12/08/76	448	668
Columbia	12/03/76	370	898
Dixie	11/29/76	56	160
Flagler	10/30/91	456	1184
Franklin	11/29/76	136	420
Gadsden	12/06/76	219	533
Gilchrist	11/30/76	62	464
Gulf	11/30/76	68	753
Hamilton	11/30/76	131	855
Hardee	11/29/76	212	10
Hernando	12/03/76	397	623
Highlands	11/29/76	535	951
Hillsborough	11/29/76	3181	1281
Jefferson	11/29/76	75	198
Lafayette	11/29/76	36	422
Lake	12/06/76	620	66
Leon	11/30/76	823	723
Levy	11/29/76	98	32
Liberty	11/29/76	25	104
Madison	12/06/76	89	124
Marion	12/08/76	779	258
Orange	12/06/76	2745	889
Osceola	11/30/76	345	524
Pasco	12/03/76	867	1165
Pinellas	12/03/76	4484	1651
Polk	11/29/76	1720	2000
Seminole	12/06/76	1105	1137
Sumter	11/30/76	181	97
Suwanee	11/29/76	146	437
Taylor	11/30/76	123	111
Volusia	12/06/76	1872	1438
Wakulla	12/07/76	53	837

TWENTY-FOURTH SUPPLEMENTAL INDENTURE dated April 1, 1979

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	06/11/79	1212	956
Bay	06/12/79	734	343
Brevard	10/30/91	3157	4212
Citrus	06/12/79	538	1687
Columbia	06/14/79	429	139
Dixie	06/12/79	68	122
Flagler	10/30/91	456	1212
Franklin	06/13/79	159	186
Gadsden	06/13/79	259	396
Gilchrist	06/12/79	77	260
Gulf	06/14/79	78	174
Hamilton	06/12/79	142	859
Hardee	06/12/79	245	558
Hernando	06/12/79	443	17
Highlands	06/13/79	620	77
Hillsborough	06/12/79	3523	1162
Jefferson	06/13/79	93	685
Lafayette	06/13/79	44	496
Lake	06/12/79	678	266
Leon	06/15/79	931	526
Levy	06/12/79	141	163
Liberty	06/13/79	30	394
Madison	06/13/79	108	655
Marion	06/13/79	976	451
Orange	06/13/79	3018	812
Osceola	06/12/79	438	115
Pasco	06/14/79	1013	126
Pinellas	06/12/79	4867	291
Polk	06/12/79	1881	2012
Seminole	06/12/79	1228	606
Sumter	06/12/79	216	642
Suwanee	06/12/79	184	514
Taylor	06/13/79	145	686
Volusia	06/12/79	2082	1430
Wakulla	06/13/79	69	884

TWENTY-FIFTH SUPPLEMENTAL INDENTURE dated April 1, 1980

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/25/80	1290	319
Bay	07/25/80	794	596
Brevard	10/30/91	3157	4238
Citrus	07/28/80	560	2030
Columbia	07/24/80	451	126
Dixie	07/24/80	73	220
Flagler	10/30/91	456	1238
Franklin	07/28/80	169	589
Gadsden	07/25/80	275	649
Gilchrist	07/24/80	84	551
Gulf	07/28/80	82	290
Hamilton	07/25/80	148	774
Hardee	07/25/80	257	823
Hernando	07/24/80	465	441
Highlands	07/29/80	658	523
Hillsborough	07/24/80	3684	411
Jefferson	07/25/80	101	387
Lafayette	07/24/80	47	586
Lake	07/24/80	705	977
Leon	07/25/80	966	426
Levy	07/25/80	161	478
Liberty	07/25/80	32	981
Madison	07/28/80	117	572
Marion	07/28/80	1027	1141
Orange	07/25/80	3127	1401
Osceola	07/30/80	489	198
Pasco	07/25/80	1077	1362
Pinellas	06/24/80	5038	2013
Polk	07/25/80	1956	1808
Seminole	07/28/80	1288	1105
Sumter	07/25/80	233	598
Suwanee	07/29/80	200	618
Taylor	07/28/80	156	740
Volusia	07/25/80	2185	587
Wakulla	07/28/80	76	879

TWENTY-SIXTH SUPPLEMENTAL INDENTURE dated November 1, *1980*

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	01/27/81	1326	527
Bay	01/26/81	823	570
Brevard	10/30/91	3157	4267
Citrus	01/28/81	570	1391
Columbia	01/27/81	461	435
Dixie	01/23/81	75	785
Flagler	10/30/91	456	1267
Franklin	01/27/81	174	320
Gadsden	01/26/81	282	356
Gilchrist	01/23/81	87	484
Gulf	01/26/81	84	307
Hamilton	01/26/81	151	44
Hardee	01/27/81	264	214
Hernando	01/26/81	476	916
Highlands	01/26/81	676	12
Hillsborough	01/26/81	3760	1223
Jefferson	01/26/81	104	658
Lafayette	01/27/81	49	175
Lake	01/27/81	717	2439
Leon	01/30/81	983	1982
Levy	01/26/81	169	716
Liberty	01/26/81	33	875
Madison	01/27/81	121	535
Marion	01/26/81	1051	47
Orange	01/26/81	3167	2388
Osceola	01/28/81	512	78
Pasco	01/26/81	1108	1247
Pinellas	12/31/80	5128	1781
Polk	01/27/81	1994	436
Seminole	01/27/81	1317	775
Sumter	01/26/81	241	211
Suwanee	01/27/81	209	696
Taylor	01/26/81	161	461
Volusia	01/26/81	2236	1396
Wakulla	01/26/81	79	837

TWENTY-SEVENTH SUPPLEMENTAL INDENTURE dated November 15, 1980

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	02/10/81	1328	880
Bay	02/10/81	825	667
Brevard	10/30/91	3157	4295
Citrus	02/13/81	571	1236
Columbia	02/09/81	462	275
Dixie	02/09/81	76	147
Flagler	10/30/91	456	1295
Franklin	02/11/81	174	590
Gadsden	02/11/81	283	105
Gilchrist	02/13/81	88	100
Gulf	02/17/81	84	561
Hamilton	02/11/81	151	256
Hardee	02/11/81	264	618
Hernando	02/10/81	477	904
Highlands	02/11/81	677	519
Hillsborough	02/10/81	3766	35
Jefferson	02/12/81	105	318
Lafayette	02/10/81	49	299
Lake	02/10/81	718	2428
Leon	02/18/81	985	1655
Levy	02/12/81	170	567
Liberty	02/12/81	34	94
Madison	02/11/81	122	47
Marion	02/10/81	1052	1660
Orange	02/11/81	3171	1797
Osceola	02/13/81	514	336
Pasco	02/10/81	1111	307
Pinellas	02/10/81	5147	951
Polk	02/11/81	1997	527
Seminole	02/11/81	1319	1660
Sumter	02/11/81	241	746
Suwanee	02/11/81	210	652
Taylor	02/11/81	161	793
Volusia	02/10/81	2241	333
Wakulla	02/11/81	80	188

TWENTY-EIGHTH SUPPLEMENTAL INDENTURE dated May 1, 1981

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	06/08/81	1351	161
Bay	07/20/81	853	623
Brevard	10/30/91	3157	4321
Citrus	06/08/81	578	919
Columbia	06/08/81	469	507
Dixie	06/09/81	78	172
Flagler	10/30/91	456	1321
Franklin	06/10/81	178	166
Gadsden	06/08/81	286	1847
Gilchrist	06/05/81	90	526
Gulf	06/09/81	85	881
Hamilton	06/08/81	152	776
Hardee	06/05/81	267	797
Hernando	06/05/81	484	1645
Highlands	06/05/81	689	338
Hillsborough	06/05/81	3814	700
Jefferson	06/09/81	107	352
Lafayette	06/05/81	50	758
Lake	06/08/81	727	209
Leon	06/08/81	996	1780
Levy	06/08/81	176	81
Liberty	06/12/81	34	859
Madison	06/08/81	125	615
Marion	06/05/81	1068	1824
Orange	06/08/81	3199	783
Osceola	06/09/81	532	1
Pasco	06/05/81	1132	1007
Pinellas	06/05/81	5201	1902
Polk	06/12/81	2022	642
Seminole	06/08/81	1340	894
Sumter	06/05/81	246	210
Suwanee	06/05/81	217	153
Taylor	06/09/81	165	536
Volusia	06/05/81	2272	1296
Wakulla	06/08/81	82	500

TWENTY-NINTH SUPPLEMENTAL INDENTURE dated September 1, 1982

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	10/06/82	1440	284
Bay	10/08/82	912	523
Brevard	10/30/91	3157	4348
Citrus	10/07/82	604	1403
Columbia	10/06/82	498	260
Dixie	10/07/82	85	2
Flagler	10/30/91	456	1348
Franklin	10/11/82	191	239
Gadsden	10/08/82	297	266
Gilchrist	10/07/82	98	657
Gulf	10/07/82	91	125
Hamilton	10/06/82	159	396
Hardee	10/07/82	281	339
Hernando	10/06/82	510	1386
Highlands	10/08/82	733	571
Hillsborough	10/06/82	4009	985
Jefferson	10/08/82	115	766
Lafayette	10/06/82	55	163
Lake	10/08/82	759	836
Leon	10/07/82	1041	20
Levy	10/06/82	198	511
Liberty	10/07/82	38	218
Madison	10/07/82	136	685
Marion	10/06/82	1128	717
Orange	10/07/82	3316	738
Osceola	10/11/82	606	68
Pasco	10/06/82	1212	1279
Pinellas	10/07/82	5411	1407
Polk	10/07/82	2110	93
Seminole	10/06/82	1416	535
Sumter	10/06/82	263	631
Suwanee	10/06/82	238	524
Taylor	10/07/82	178	879
Volusia	10/06/82	2391	1879
Wakulla	10/07/82	91	306

THIRTIETH SUPPLEMENTAL INDENTURE dated October 1, 1982

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/02/82	1450	90
Bay	12/06/82	916	1538
Brevard	10/30/91	3157	4364
Citrus	12/03/82	607	1034
Columbia	12/06/82	501	729
Dixie	12/06/82	86	49
Flagler	10/30/91	456	1364
Franklin	12/07/82	192	448
Gadsden	12/06/82	298	608
Gilchrist	12/03/82	100	18
Gulf	12/07/82	91	744
Hamilton	12/06/82	160	118
Hardee	12/08/82	283	11
Hernando	12/03/82	513	992
Highlands	12/07/82	738	221
Hillsborough	12/03/82	4033	293
Jefferson	12/06/82	117	9
Lafayette	12/06/82	55	444
Lake	12/03/82	763	19
Leon	12/07/82	1047	812
Levy	12/06/82	201	136
Liberty	12/08/82	38	547
Madison	12/07/82	137	808
Marion	12/07/82	1135	1015
Orange	12/06/82	3330	2301
Osceola	12/09/82	615	721
Pasco	12/06/82	1222	1592
Pinellas	11/23/82	5434	229
Polk	12/08/82	2121	118
Seminole	12/06/82	1425	1476
Sumter	12/06/82	265	768
Suwanee	12/07/82	240	699
Taylor	12/06/82	180	189
Volusia	12/06/82	2406	460
Wakulla	12/06/82	92	272

THIRTY-FIRST SUPPLEMENTAL INDENTURE dated November 1, 1991

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/05/91	1836	2215
Bay	12/04/91	1347	1335
Brevard	12/05/91	3165	1204
Citrus	12/04/91	917	725
Columbia	12/04/91	753	1847
Dixie	12/09/91	156	90
Flagler	12/04/91	458	1266
Franklin	12/04/91	364	11
Gadsden	12/04/91	386	1240
Gilchrist	12/09/91	182	573
Gulf	12/04/91	148	72
Hamilton	12/04/91	294	236
Hardee	12/04/91	420	322
Hernando	12/03/91	843	1139
Highlands	12/03/91	1161	1860
Hillsborough	12/04/91	6449	1412
Jefferson	12/04/91	225	39
Lafayette	12/05/91	87	430
Lake	12/04/91	1138	1083
Leon	12/04/91	1530	452
Levy	12/05/91	446	454
Liberty	12/04/91	68	508
Madison	12/04/91	258	173
Marion	12/04/91	1787	161
Orange	12/06/91	4352	22
Osceola	12/05/91	1042	587
Pasco	12/03/91	2071	503
Pinellas	11/13/91	7731	740
Polk	12/06/91	3041	1252
Seminole	12/05/91	2364	1942
Sumter	12/03/91	443	254
Suwanee	12/05/91	423	515
Taylor	12/04/91	296	232
Volusia	12/09/91	3712	968
Wakulla	12/05/91	185	524

THIRTY-SECOND SUPPLEMENTAL INDENTURE dated December 1, 1992

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/30/92	1888	2338
Bay	12/30/92	1410	42
Brevard	12/29/92	3256	2503
Citrus	12/29/92	965	231
Columbia	12/30/92	769	532
Dixie	12/30/92	165	484
Flagler	12/30/92	480	212
Franklin	12/30/92	399	1
Gadsden	12/30/92	399	1762
Gilchrist	12/30/92	194	693
Gulf	01/06/93	157	343
Hamilton	12/29/92	314	215
Hardee	12/31/92	439	211
Hernando	12/29/92	894	688
Highlands	12/29/92	1200	1665
Hillsborough	12/30/92	6838	810
Jefferson	12/30/92	250	196
Lafayette	12/30/92	92	129
Lake	12/30/92	1203	323
Leon	01/07/93	1611	2296
Levy	12/29/92	479	312
Liberty	12/30/92	73	427
Madison	12/30/92	292	205
Marion	12/29/92	1888	1815
Orange	12/30/92	4506	2985
Osceola	12/31/92	1102	2325
Pasco	12/29/92	3101	950
Pinellas	12/15/92	8120	1705
Polk	12/31/92	3185	899
Seminole	12/29/92	2525	1408
Sumter	12/29/92	471	468
Suwanee	12/29/92	449	469
Taylor	01/21/93	313	221
Volusia	12/30/92	3797	1647
Wakulla	12/31/92	204	765

THIRTY-THIRD SUPPLEMENTAL INDENTURE dated December 1, 1992

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/30/92	1888	2426
Bay	12/30/92	1410	130
Brevard	12/29/92	3256	2592
Citrus	12/29/92	965	319
Columbia	12/30/92	769	622
Dixie	12/30/92	165	572
Flagler	12/30/92	480	300
Franklin	12/30/92	399	89
Gadsden	12/30/92	399	1850
Gilchrist	12/30/92	195	1
Gulf	01/06/93	157	431
Hamilton	12/29/92	315	1
Hardee	12/31/92	439	299
Hernando	12/29/92	894	776
Highlands	12/29/92	1200	1754
Hillsborough	12/30/92	6838	898
Jefferson	12/30/92	250	285
Lafayette	12/30/92	92	217
Lake	12/30/92	1203	411
Leon	01/07/93	1611	2384
Levy	12/29/92	479	400
Liberty	12/30/92	73	515
Madison	12/30/92	292	293
Marion	12/29/92	1888	1903
Orange	12/30/92	4506	3073
Osceola	12/31/92	1102	2413
Pasco	12/29/92	3101	1038
Pinellas	12/15/92	8120	1795
Polk	12/31/92	3185	987
Seminole	12/29/92	2525	1496
Sumter	12/29/92	471	556
Suwanee	12/29/92	449	595
Taylor	01/21/93	313	309
Volusia	12/30/92	3797	1735
Wakulla	12/31/92	204	853

THIRTY-FOURTH SUPPLEMENTAL INDENTURE dated February 1, 1993

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	02/23/93	1895	1712
Bay	02/22/93	1418	1202
Brevard	02/22/93	3268	4928
Citrus	03/03/93	972	1372
Columbia	02/23/93	771	1030
Dixie	02/23/93	166	771
Flagler	02/23/93	483	86
Franklin	02/23/93	404	209
Gadsden	02/22/93	402	153
Gilchrist	02/22/93	196	612
Gulf	02/22/93	158	636
Hamilton	02/22/93	317	37
Hardee	02/26/93	442	29
Hernando	02/22/93	901	1009
Highlands	02/23/93	1206	1393
Hillsborough	02/23/93	6891	182
Jefferson	02/23/93	254	267
Lafayette	02/22/93	92	788
Lake	02/22/93	1211	1060
Leon	02/23/93	1621	51
Levy	02/22/93	484	459
Liberty	02/22/93	74	366
Madison	02/22/93	297	50
Marion	03/01/93	1902	1706
Orange	03/01/93	4527	4174
Osceola	02/23/93	1111	2070
Pasco	03/01/93	3118	1205
Pinellas	02/09/93	8173	382
Polk	02/22/93	3203	2186
Seminole	02/22/93	2547	765
Sumter	02/22/93	475	750
Suwanee	02/23/93	454	51
Taylor	02/25/93	314	853
Volusia	02/23/93	3808	3551
Wakulla	02/23/93	207	396

THIRTY-FIFTH SUPPLEMENTAL INDENTURE dated March 1, 1993

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	03/22/93	1898	2769
Bay	03/23/93	1423	659
Brevard	03/22/93	3275	3473
Citrus	03/22/93	975	1
Columbia	03/24/93	772	1536
Dixie	03/23/93	167	499
Flagler	03/23/93	484	1113
Franklin	03/22/93	407	47
Gadsden	03/22/93	403	66
Gilchrist	03/22/93	197	704
Gulf	03/22/93	159	388
Hamilton	03/22/93	320	1
Hardee	03/22/93	443	137
Hernando	03/22/93	905	480
Highlands	03/22/93	1210	47
Hillsborough	03/22/93	6917	972
Jefferson	03/24/93	257	40
Lafayette	03/23/93	93	218
Lake	03/23/93	1216	1165
Leon	03/23/93	1626	1941
Levy	03/23/93	487	375
Liberty	03/22/93	74	627
Madison	03/22/93	299	211
Marion	03/22/93	1910	738
Orange	03/23/93	4539	2634
Osceola	03/25/93	1115	2511
Pasco	03/22/93	3129	149
Pinellas	03/10/93	8200	2030
Polk	03/22/93	3214	1331
Seminole	03/22/93	2559	1330
Sumter	03/22/93	478	191
Suwanee	03/24/93	456	58
Taylor	03/26/93	316	580
Volusia	03/23/93	3814	4453
Wakulla	03/22/93	208	563

THIRTY-SIXTH SUPPLEMENTAL INDENTURE dated July 1, 1993

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/06/93	1919	2335
Bay	08/09/93	1447	1661
Brevard	08/05/93	3312	2304
Citrus	08/06/93	994	111
Columbia	08/09/93	778	736
Dixie	08/10/93	171	595
Flagler	08/06/93	493	183
Franklin	08/16/93	423	78
Gadsden	08/06/93	407	1440
Gilchrist	08/06/93	202	372
Gulf	08/06/93	162	831
Hamilton	08/06/93	326	301
Hardee	08/06/93	450	623
Hernando	08/09/93	925	1936
Highlands	08/06/93	1225	1608
Hillsborough	08/05/93	7071	222
Jefferson	08/10/93	266	252
Lafayette	08/09/93	95	394
Lake	08/06/93	1241	430
Leon	08/09/93	1660	1955
Levy	08/06/93	500	395
Liberty	08/06/93	76	362
Madison	08/06/93	312	20
Marion	08/06/93	1948	1022
Orange	08/09/93	4602	366
Osceola	08/06/93	1138	832
Pasco	08/05/93	3182	104
Pinellas	07/20/93	8342	522
Polk	08/05/93	3268	1251
Seminole	08/09/93	2627	330
Sumter	08/05/93	489	700
Suwanee	08/09/93	467	488
Taylor	08/06/93	323	490
Volusia	08/06/93	3848	2752
Wakulla	08/06/93	217	104

THIRTY-SEVENTH SUPPLEMENTAL INDENTURE dated December 1, 1993

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/29/93	1942	1768
Bay	12/29/93	1473	1090
Brevard	12/28/93	3353	2186
Citrus	12/29/93	1013	1791
Columbia	12/30/93	784	1174
Dixie	01/04/94	175	744
Flagler	12/30/93	503	269
Franklin	12/30/93	437	69
Gadsden	12/29/93	412	1638
Gilchrist	01/03/94	207	597
Gulf	12/29/93	166	710
Hamilton	12/29/93	334	78
Hardee	12/28/93	458	139
Hernando	12/30/93	947	1037
Highlands	12/29/93	1241	1888
Hillsborough	12/29/93	7235	1829
Jefferson	12/30/93	276	231
Lafayette	12/29/93	97	746
Lake	12/29/93	1267	2229
Leon	12/29/93	1698	1017
Levy	12/30/93	512	733
Liberty	12/29/93	78	291
Madison	12/29/93	324	302
Marion	12/29/93	1990	1962
Orange	12/29/93	4675	2208
Osceola	12/30/93	1163	2641
Pasco	12/29/93	3239	112
Pinellas	12/15/93	8502	2162
Polk	12/28/93	3327	562
Seminole	12/28/93	2703	466
Sumter	12/28/93	502	167*
Suwanee	12/29/93	478	324
Taylor	12/29/93	330	533
Volusia	12/29/93	3885	2736
Wakulla	12/30/93	224	727

* Due to a scriveners error, the Thirty-Ninth and Fortieth Supplemental Indentures to the Original Indenture erroneously indicated a page number of 157.

THIRTY-EIGHTH SUPPLEMENTAL INDENTURE dated July 25, 1994

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	08/08/94	1975	2678
Bay	08/08/94	1516	432
Brevard	08/08/94	3412	3309
Citrus	08/08/94	1044	2108
Columbia	08/08/94	794	188
Dixie	08/11/94	183	3
Flagler	08/08/94	516	1458
Franklin	08/10/94	465	42
Gadsden	08/09/94	422	570
Gilchrist	08/10/94	216	477
Gulf	08/08/94	172	664
Hamilton	08/08/94	347	189
Hardee	08/08/94	471	495
Hernando	09/06/94	983	887
Highlands	08/08/94	1267	791
Hillsborough	08/10/94	7485	745
Jefferson	08/09/94	298	22
Lafayette	08/09/94	101	626
Lake	08/09/94	1311	1274
Leon	08/08/94	1754	594
Levy	08/08/94	533	45
Liberty	08/09/94	81	566
Madison	08/08/94	348	172
Marion	08/10/94	2060	1272
Orange	08/09/94	4779	4850
Osceola	08/08/94	1205	1060
Pasco	08/08/94	3326	1162
Pinellas	07/25/94	8734	1574
Polk	08/08/94	3423	2168
Seminole	08/08/94	2809	131
Sumter	08/08/94	524	256
Suwanee	08/08/94	500	170
Taylor	08/09/94	342	576
Volusia	08/11/94	3942	4371
Wakulla	08/10/94	239	322

THIRTY-NINTH SUPPLEMENTAL INDENTURE dated July 1, 2001

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/16/01	2371	1703
Bay	07/24/01	2052	225
Brevard	07/24/01	4387	206
Citrus	07/16/01	1440	322
Columbia	07/24/01	931	1741
Dixie	07/23/01	262	1
Flagler	07/24/01	758	320
Franklin	07/26/01	671	542
Gadsden	07/23/01	529	134
Gilcrest	07/23/01	2001	3068
Gulf	07/24/01	262	872
Hamilton	07/23/01	504	59
Hardee	07/23/01	614	764
Hernando	07/16/01	1437	619
Highlands	07/16/01	1556	1380
Hillsborough	07/23/01	10952	1626
Jefferson	07/23/01	471	268
Lafayette	07/23/01	169	348
Lake	07/16/01	1974	2275
Leon	07/23/01	2530	74
Levy	07/23/01	752	726
Liberty	07/23/01	124	311
Madison	07/24/01	587	48
Manatee	07/23/01	1692	6974
Marion	07/16/01	2987	1131
Orange	07/16/01	6302	3365
Osceola	07/16/01	1902	1112
Pasco	07/16/01	4667	77
Pinellas	07/13/01	11475	2488
Polk	07/16/01	4751	1
Seminole	07/16/01	4128	170
Sumter	07/16/01	894	40
Suwannee	07/23/01	877	77
Taylor	07/23/01	464	215
Volusia	07/17/01	4714	4356
Wakulla	07/23/01	414	599

FORTIETH SUPPLEMENTAL INDENTURE dated July 1, 2002

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	07/19/02	2486	439
Bay	07/19/02	2164	520
Brevard	07/01/01	4641	2591
Citrus	07/19/02	1521	2
Columbia	07/19/02	958	500
Dixie	07/19/02	277	1
Flagler	07/24/02	838	776
Franklin	07/24/02	706	23
Gadsden	07/19/02	548	415
Gilchrist*	07/19/02	Instrument Number 2002 3363	
Gulf	07/19/02	285	369
Hamilton	07/19/02	530	143
Hardee	07/19/02	630	147
Hernando	07/19/02	1552	745
Highlands	07/19/02	1616	1919
Hillsborough	07/19/02	11790	0680
Jefferson	07/22/02	0492	0001
Lafayette	07/19/02	181	406
Lake	07/22/02	02145	1576
Leon	07/19/02	R2697	01718
Levy	07/19/02	795	531
Liberty	07/19/02	131	454
Madison	07/19/02	627	171
Manatee	07/19/02	1759	970
Marion	07/19/02	3203	0458
Orange	07/23/02	6573	5463
Osceola	07/22/02	2082	1419
Pasco	07/19/02	5012	1362
Pinellas	07/26/02	12128	1700
Polk	07/19/02	5064	0027
Seminole	07/23/02	4468	0429
Sumter	07/19/02	988	512
Suwannee	07/19/02	948	7
Taylor	07/19/02	484	562
Volusia	07/19/02	4898	2002
Wakulla	07/22/02	450	344

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-FIRST SUPPLEMENTAL INDENTURE dated February 1, 2003

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	03/10/03	2620	1182
Bay	03/20/03	2252	1616
Brevard	03/10/03	4845	847
Citrus	03/10/03	1580	537
Columbia	03/10/03	976	2505
Dixie	03/10/03	285	654
Flagler	03/10/03	905	1523
Franklin	03/12/03	729	424
Gadsden	03/10/03	561	1091
Gilchrist*	03/10/03	Instrument Number 2003	1224
Gulf	03/10/03	301	432
Hamilton	03/10/03	543	358
Hardee	03/10/03	640	218
Hernando	03/07/03	1636	204
Highlands	03/10/03	1660	726
Hillsborough	03/10/03	12427	1748
Jefferson	03/10/03	507	98
Lafayette	03/10/03	189	107
Lake	03/10/03	2276	2224
Leon	03/11/03	2827	95
Levy	03/10/03	826	208
Liberty	03/11/03	136	479
Madison	03/09/03	653	69
Manatee	03/07/03	1809	6624
Marion	03/10/03	3363	1414
Orange	03/10/03	6820	89
Osceola	03/10/03	2208	1762
Pasco	03/07/03	5267	216
Pinellas	03/06/03	12582	1011
Polk	03/06/03	5289	1762
Seminole	03/10/03	4745	970
Sumter	03/07/03	1052	4
Suwannee	03/10/03	995	83
Taylor	03/10/03	497	542
Volusia	03/10/03	5033	4056
Wakulla	03/10/03	478	79

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-SECOND SUPPLEMENTAL INDENTURE dated April 1, 2003

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	05/27/2003	2676	753
Bay	05/27/2003	2283	585
Brevard	06/06/2003	4935	345
Citrus	05/23/2003	1604	305
Columbia	05/23/2003	984	87
Dixie	05/23/2003	289	447
Flagler	05/27/2003	935	151
Franklin	05/27/2003	739	166
Gadsden	05/23/2003	566	840
Gilchrist*	05/23/2003	Instrument Number 2003002716	
Gulf	05/27/2003	307	784
Hamilton	05/23/2003	549	1
Hardee	05/28/2003	644	670
Hernando	05/23/2003	1671	1084
Highlands	05/23/2003	1676	1168
Hillsborough	05/28/2003	12682	320
Jefferson	05/23/2003	512	367
Lafayette	05/23/2003	191	373
Lake	05/22/2003	2324	1507
Leon	05/28/2003	2874	1027
Levy	05/27/2003	837	42
Liberty	05/27/2003	138	218
Madison	05/23/2003	664	225
Manatee	05/28/2003	1831	1979
Marion	05/30/2003	3426	1046
Orange	05/23/2003	6925	2125
Osceola	05/22/2003	2256	2207
Pasco	05/23/2003	5370	1906
Pinellas	05/23/2003	12767	1631
Polk	05/23/2003	5372	1233
Seminole	05/30/2003	4843	1879
Sumter	05/30/2003	1076	307
Suwannee	05/23/2003	1013	263
Taylor	05/28/2003	502	773
Volusia	06/02/2003	5084	4311
Wakulla	05/23/2003	488	388

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-THIRD SUPPLEMENTAL INDENTURE dated November 1, 2003

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	12/30/2003	2831	1359
Bay	01/12/2004	2385	484
Brevard	01/08/2004	5166	2137
Citrus	12/29/2003	1675	939
Columbia	12/30/2003	1003	767
Dixie	12/30/2003	300	401
Flagler	12/29/2003	1024	1365
Franklin	12/30/2003	769	78
Gadsden	12/29/2003	580	1923
Gilchrist*	12/30/2003	Instrument Number 2003006794	
Gulf	12/30/2003	327	232
Hamilton	12/29/2003	563	163
Hardee	12/29/2003	656	951
Hernando	12/31/2003	1776	1140
Highlands	12/29/2003	1727	647
Hillsborough	12/31/2003	13433	1463
Jefferson	12/30/2003	530	192
Lafayette	12/30/2003	199	454
Lake	12/30/2003	2478	691
Leon	01/08/2004	3018	255
Levy	01/05/2004	868	897
Liberty	12/30/2003	142	561
Madison	12/30/2003	695	129
Manatee	12/30/2003	1891	3077
Marion	01/05/2004	3610	1489
Orange	12/30/2003	7245	2525
Osceola	01/07/2004	2418	906
Pasco	12/30/2003	5676	531
Pinellas	12/23/2003	13265	2523
Polk	12/29/2003	5624	1278
Seminole	12/30/2003	5149	1458
Sumter	01/06/2004	1156	447
Suwannee	12/30/2003	1065	398
Taylor	12/30/2003	516	670
Volusia	12/29/2003	5232	3126
Wakulla	12/29/2003	518	436

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-FOURTH SUPPLEMENTAL INDENTURE dated August 1, 2004

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	09/08/2004	2989	679
Bay	09/20/2004	2503	1164
Brevard	09/10/2004	5358	4062
Citrus	09/08/2004	1761	1476
Columbia	09/08/2004	1025	1081
Dixie	09/08/2004	313	405
Flagler	09/10/2004	1141	1282
Franklin	09/07/2004	811	160
Gadsden	09/09/2004	596	209
Gilchrist*	09/08/2004	Instrument Number 2004004967	
Gulf	09/08/2004	351	826
Hamilton	09/08/2004	579	91
Hardee	09/07/2004	669	579
Hernando	09/09/2004	1897	1207
Highlands	09/07/2004	1787	1955
Hillsborough	09/16/2004	14220	1091
Jefferson	09/08/2004	552	115
Lafayette	09/10/2004	209	329
Lake	09/09/2004	2652	1330
Leon	09/10/2004	3158	1432
Levy	09/08/2004	905	525
Liberty	09/09/2004	148	295
Madison	09/08/2004	728	181
Manatee	09/09/2004	1955	6519
Marion	09/14/2004	3819	714
Orange	09/17/2004	7618	4387
Osceola	09/15/2004	2595	1666
Pasco	09/15/2004	6027	311
Pinellas	09/09/2004	13817	1552
Polk	09/09/2004	5915	905
Seminole	09/14/2004	5450	663
Sumter	09/17/2004	1267	646
Suwannee	09/08/2004	1133	1
Taylor	09/07/2004	532	603
Volusia	09/16/2004	5399	4694
Wakulla	09/08/2004	556	566

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-FIFTH SUPPLEMENTAL INDENTURE dated May 1, 2005

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	05/25/2005	3130	992
Bay	05/26/2005	2614	528
Brevard	05/31/2005	5474	4268
Citrus	06/03/2005	1862	2370
Columbia	05/26/2005	1047	766
Dixie	05/27/2005	327	196
Flagler	05/26/2005	1254	1518
Franklin	05/26/2005	853	323
Gadsden	05/26/2005	612	684
Gilchrist*	05/26/2005	Instrument Number 2005003072	
Gulf	05/26/2005	378	613
Hamilton	05/26/2005	594	4
Hardee	05/25/2005	683	104
Hernando	05/27/2005	2032	1078
Highlands	05/25/2005	1856	568
Hillsborough	06/01/2005	15064	90
Jefferson	05/24/2005	565	810
Lafayette	05/27/2005	220	324
Lake	05/26/2005	2843	2013
Leon	05/27/2005	3297	1711
Levy	05/26/2005	948	157
Liberty	05/27/2005	154	54
Madison	05/27/2005	760	251
Manatee	05/27/2005	2024	1257
Marion	06/07/2005	4061	390
Orange	05/24/2005	7983	1610
Osceola	06/09/2005	2802	2269
Pasco	05/27/2005	6391	357
Pinellas	05/23/2005	14330	1811
Polk	05/31/2005	6225	332
Seminole	05/27/2005	5741	1576
Sumter	05/26/2005	1382	1
Suwannee	05/26/2005	1199	54
Taylor	05/27/2005	549	201
Volusia	06/03/2005	5567	2445
Wakulla	05/27/2005	595	778

* Gilchrist County utilizes an instrument number indexing system rather than a book/page indexing system.

FORTY-SIXTH SUPPLEMENTAL INDENTURE dated September 1, 2007

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	10/15/2007	3691	1036
Bay	10/15/2007	2984	1808
Brevard	10/19/2007	5819	7058
Citrus	10/16/2007	2167	1649
Columbia	10/15/2007	1133	1243
Dixie	10/18/2007	379	107
Flagler	10/16/2007	1620	800
Franklin	10/15/2007	950	1
Gadsden	10/17/2007	681	453
Gilchrist*	10/16/2007	Instrument Number 2007006252	
Gulf	10/18/2007	448	17
Hamilton	10/15/2007	652	1
Hardee*	10/17/2007	Instrument Number 200725009084	
Hernando	10/15/2007	2499	1518
Highlands	10/16/2007	2103	1577
Hillsborough	10/17/2007	18191	597
Jefferson*	10/19/2007	Instrument Number 200733129980	
Lafayette	10/16/2007	262	275
Lake	10/16/2007	3524	2021
Leon	10/16/2007	3778	1808
Levy	10/15/2007	1097	616
Liberty	10/15/2007	175	1
Madison	10/15/2007	881	284
Manatee	10/16/2007	2231	362
Marion	10/16/2007	4910	461
Orange	10/17/2007	9473	4445
Osceola	10/15/2007	3578	1571
Pasco	10/16/2007	7663	343
Pinellas	10/11/2007	16013	1452
Polk	10/16/2007	7455	1559
Seminole	11/20/2007	6871	27
Sumter	10/16/2007	1854	167
Suwannee	10/15/2007	1420	130
Taylor	10/15/2007	610	413
Volusia	10/16/2007	6141	278
Wakulla	10/15/2007	731	256

* Gilchrist, Hardee and Jefferson Counties utilize an instrument number indexing system rather than a book/page indexing system.

Surface Transportation Board filing : Document number 27455, recorded on April 7, 2008

FORTY-SEVENTH SUPPLEMENTAL INDENTURE dated December 1, 2007

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	1/11/2008	3729	1099
Bay	1/11/2008	3012	924
Brevard	1/16/2008	5838	4532
Citrus	1/11/2008	2187	112
Columbia	1/11/2008	1140	1338
Dixie	1/17/2008	383	1
Flagler	1/14/2008	1638	232
Franklin	1/11/2008	956	429
Gadsden	1/15/2008	686	1438
Gilchrist*	1/11/2008	Instrument number 2008000227	
Gulf	1/14/2008	452	419
Hamilton	1/11/2008	656	256
Hardee*	1/10/2008	Instrument number 200825000197	
Hernando	1/11/2008	2525	829
Highlands	1/10/2208	2119	119
Hillsborough	1/14/2008	18375	428
Jefferson*	1/11/2008	Instrument number 200833000172	
Lafayette	1/14/2008	265	337
Lake	1/11/2008	3567	2417
Leon	1/14/2008	3812	243
Levy	1/11/2008	1108	521
Liberty	1/14/2008	176	526
Madison	1/11/2008	891	71
Manatee	1/11/2008	2242	4715
Marion	1/14/2008	4964	518
Orange	2/18/2008	9602	277
Osceola	1/10/2008	3624	1400
Pasco	1/11/2008	7735	1309
Pinellas	1/15/2008	16119	240
Polk	1/14/2008	7530	1569
Seminole	1/14/2008	6907	866
Sumter	1/11/2008	1891	308
Suwannee	1/11/2008	1436	400
Taylor	1/11/2008	615	164
Volusia	1/14/2008	6179	2404
Wakulla	1/11/2008	741	22

*Gilchrest, Hardee and Jefferson Counties utilize an instrument number indexing system rather than a book/page indexing system.

Surface Transportation Board filing: Document number 27455-A, recorded on April 7, 2008

FORTY-EIGHTH SUPPLEMENTAL INDENTURE dated June 1, 2008

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	6/13/2008	3799	651
Bay	6/30/2008	3063	715
Brevard	7/02/2008	5874	3269
Citrus	6/13/2008	2223	1494
Columbia	6/30/2008	1153	1442
Dixie	7/01/2008	391	1
Flagler	7/01/2008	1669	378
Franklin	6/30/2008	968	373
Gadsden	6/30/2008	696	1067
Gilchrist*	7/03/2008	Instrument number 2008003591	
Gulf	6/30/2008	461	1
Hamilton	6/30/2008	665	310
Hardee*	6/27/2008	Instrument number 200825005011	
Hernando	6/13/2008	2570	1746
Highlands	6/13/2008	2145	308
Hillsborough	7/02/2008	18729	956
Jefferson*	6/30/2008	Instrument number 200833002125	
Lafayette*	7/08/2008	Instrument number 200834001431	
Lake	6/13/2008	3640	1530
Leon	6/30/2008	3875	1363
Levy	6/13/2008	1127	115
Liberty	7/07/2008	181	252
Madison	6/30/2008	912	285
Manatee	6/27/2008	2264	7699
Marion	6/13/2008	5051	1339
Orange	6/13/2008	9711	4102
Osceola	6/13/2008	3699	1687
Pasco	6/13/2008	7860	610
Pinellas	6/12/2008	16285	454
Polk	6/13/2008	7653	1238
Seminole	6/13/2008	7011	1530
Sumter	6/13/2008	1961	271
Suwannee	6/30/2008	1470	367
Taylor	6/30/2008	624	665
Volusia	6/13/2008	6243	719
Wakulla	6/30/2008	759	351

*Gilchrest, Hardee, Jefferson and Lafayette Counties utilize an instrument number indexing system rather than a book/page indexing system.

Surface Transportation Board filing: Document number 27455-B, recorded on August 6, 2008

FORTY-NINTH SUPPLEMENTAL INDENTURE dated March 1, 2010

STATE OF FLORIDA

County	Date of Recordation	Book	Page
Alachua	4/08/2010	3947	1403
Bay	4/08/2010	3231	1321
Brevard	4/09/2010	6145	993
Citrus	4/08/2010	2348	2
Columbia	4/08/2010	1192	803
Dixie	4/15/2010	415	183
Flagler	4/12/2010	1763	1207
Franklin	4/09/2010	1009	1
Gadsden	4/08/2010	729	1001
Gilchrist*	4/08/2010	Instrument number 2010001440	
Gulf	4/08/2010	489	612
Hamilton	4/08/2010	693	1
Hardee*	4/08/2010	Instrument number 201025002243	
Hernando	4/08/2010	2732	1794
Highlands	4/08/2010	2233	1848
Hillsborough	4/13/2010	19814	55
Jefferson*	4/09/2010	Instrument number 201033004428	
Lafayette*	4/08/2010	Instrument number 201034000540	
Lake	4/09/2010	3892	1816
Leon	4/08/2010	4101	1507
Levy	4/08/2010	1195	600
Liberty	4/13/2010	192	87
Madison	4/09/2010	982	1
Manatee	4/08/2010	2334	6690
Marion	4/08/2010	5341	1488
Orange	4/08/2010	10026	4585
Osceola	4/09/2010	3970	977
Pasco	4/08/2010	8306	1585
Pinellas	4/05/2010	16876	1530
Polk	4/09/2010	8112	1962
Seminole	4/08/2010	7362	894
Sumter	4/08/2010	2179	82
Suwannee	4/08/2010	1583	68
Taylor	4/08/2010	652	229
Volusia	4/12/2010	6464	1
Wakulla	4/08/2010	822	403

*Gilchrest, Hardee, Jefferson and Lafayette Counties utilize an instrument number indexing system rather than a book/page indexing system

Surface Transportation Board filing: Document number 27455-C, recorded on May 10, 2010

EXHIBIT B

PROPERTY DESCRIPTIONS

Doc Type	Grantor	County	State	Record Date	Deed Book	Deed Page	Section Township Range	Notes
TR	METROMONT CORPORATION	Polk	FL	7/17/2008	7678	1218	20-30S-25E	E 40' of that por of E 1/2 of SE 1/4 of SE 1/4 of Section lying W of US 17 (SR 35) less the S 910.6' and the N 302.32'
TR	MONK, BRENT	Polk	FL	8/4/2008	6905	1009	16-30S-26E	M & B, COM AT THE SW COR OF SEC
TR	THAYER JR., THOMAS A.	Polk	FL	8/11/2008	7694	1481	35-28S-27E	N 50' OF THE E 526.56' OF THE S 1/2 OF SW 1/4 OF NW 1/4 OF SEC
TR	HORNSBY, A. A.	Polk	FL	8/22/2008	7703	1409	12-28S-27E	SE 1/4 OF SE 1/4 & E 15 A. OF SW 1/4 OF SE 1/4
TR	HORNSBY, A. A.	Polk	FL	8/22/2008	7703	1416	12-28S-27E	SE 1/4 OF SE 1/4 & E 15 A. OF SW 1/4 OF SE 1/4
TR	CHIEFLAND, CITY OF	Levy	FL	1/15/2009	1150	140	06-12S-15E	BEG AT THE INTERSECTION OF THE E LINE OF SEC 1 AND THE WLY LINE OF THE ABANDONED CSX RR ROW THEN M & B:
TR	MIDWAY BAPTIST CHURCH, INC.	Taylor	FL	11/4/2009	645	395	02-04S-07E	BOWDEN SUBD, PLAT 1/188, COM AT THE SE COR OF THE SW 1/4 OF SEC THEN M & B;
TR	MAROTTE, WILLIAM F.	Volusia	FL	11/4/2009	6413	3520	12-17S-29E	THAT PORTION OF VACATED WISCONSIN AVE BEING A 25' PLATTED ROW LYING S OF BLK 5, UNIVERSITY HIGHLANDS, MB 10/225; PARCEL HAS BEEN RE-SUBDIVIDED INTO HIGHLANDS SUB MB 54/177 - PLAT SHOWS EASEMENT OVER S 30' TO CENTERLINE OF VACATED WISCONSIN AVE
TR	KBC DEVELOPMENT, INC.	Seminole	FL	11/12/2009	7286	1762	21-19S-30E	BELL'S SUBD, LOTS 10-11; ST. JOSEPH'S SUBD LOT 28

Doc Type	Grantor	County	State	Record Date	Deed Book	Deed Page	Section Township Range	Notes
TR	ST. PETERSBURG, CITY OF	Pinellas	FL	03/11/2010	16854	754	20-31S-16E	LOT 23, BLK 15, PASADENA ESTATES, PB 6/3 IN SW 1/4
TR	HARRINGTON / MISHLER, LLC.	Orange	FL	03/19/2010	10017	2495	28-22S-31E	COM SE COR OF NE 1/4 THEN M & B
TR	SHIVER, JR., LLOYD ALTON	Franklin	FL	03/24/2010	1007	784	01-09S-08W	GREATER APALACHICOLA, BLK 259, THE E PORTION OF A 2 ACRE TRACT, ETC. IN SW 1/4 OF SW 1/4
TR	MARKS, BARBARA A.	Franklin	FL	03/24/2010	1007	778	01-09S-08W	GREATER APALACHICOLA, LOTS 4 THROUGH 15, BLK 258
TR	CAUTHEN, JERRY	Franklin	FL	04/05/2010	1008	418	01-09S-08W	GREATER APALACHICOLA, LOTS 1, 2 AND 3, BLK 258
TR	SHORECREST PREPARATORY SCHOOL, INC.	Pinellas	FL	04/15/2010	16887	1234	06-31S-17E	PORTION OF 06-31S-17E
TR	EXTRA SPACE PROPERTIES TWENTY, LLC.	Orange	FL	05/05/2010	10040	1470	28-22S-31E	PT OF SECTIONS 27-22S-31E AND 28-22S-31E DESC AS BEG SW COR OF NW 1/4 OF SEC 27 THEN M & B
TR	DEAN WOODS HOMEOWNERS ASSOCIATION, INC.	Orange	FL	05/05/2010	10040	1474	29-22S-31E	TRACTS A, J & E, PLAT FOR DEAN WOODS, PLAT 39/140
TR	PANTRY, INC. (THE)	Orange	FL	05/14/2010	10044	1312	29-22S-31E	DEAN WOODS PHASE ONE, 34/124 LOT 1
TR	FIELDSTREAM NORTH HOMEOWNERS ASSOCIATION, INC.	Orange	FL	05/14/2010	10044	1321	29-22S-31E	TRACTS 1-G, FIELDSTREAM NORTH PHASE 2, PLAT 41/133 AND TRACTS 1-K, 1-J, 1-L, 1-F AND 1-C, FIELDSTREAM NORTH, PLAT 40/67
D	ST. JOE TIMBERLAND COMPANY OF DELAWARE, L.L.C.	Wakulla	FL	06/02/2010	827	199	26-03S-01E	BEGIN AT A LITEWOOD HUB MARKING THE SW CORNER OF SEC.

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TR	LAKE KEHOE PRESERVE HOMEOWNERS ASSOCIATION, INC.	Orange	FL	06/04/2010	10054	3190	28-22S-31E	LAKE KEHOE PRESERVE, TRACTS H. L AND G, PLAT 45/87
TR	XL RANCH LIMITED PARTNERSHIP	Polk	FL	06/08/2010	8152	1087	12-30S-26E 13-30S-26E 18-30S-27E	E1/2 OF NE 1/4 IN SEC 13 AND ALL OF SEC N & W OF RR ROW IN SEC 18 AND E3/4 OF SW 3/4 AND SW 1/4 OF SW 1/4 IN SEC 12
TR	STOKES, ROBERT G.	Polk	FL	06/08/2010	8152	1393	01-30S-26E06-30S-27E12-30S-26E	N1/4 OF SEC 12 AND SE 1/4 OF SEC 1 AND W 1/2 OF SR 60 AND W OF CSX ROW
TR	REYES-JONES, MARIA	Orange	FL	06/10/2010	10058	5294	12-22S-29E	LOT 1, BLK A, LAWNDALE ANNEX, PLAT J/50
TR	HAFELE, ERNEST M.	Polk	FL	06/14/2010	8157	778	04-31S-25E	ALL THAT PART OF SEC LYING W OF US HWY 17
TR	CLEAR SPRINGS ENTERPRISES LLC.	Polk	FL	06/15/2010	8157	1203	08-31S-25E	N3/4 OF E1/2 LESS S100'
TR	CLEAR SPRINGS LAND COMPANY, LLC.	Polk	FL	06/15/2010	8157	1208	34-30S-25E	E1/4 OF SE1/4 OF SB1/4 OF SEC
TR	HUTCHESON, MAURICE A., TRUST U/W	Polk	FL	06/15/2010	8157	1210	36-30S-25E	THE N 1/2 OF THE NE 1/4 OF SEC
TR	MONK, BRENT I.	Polk	FL	06/15/2010	8157	1205	16-30S-26E	SW 1/4 OF SW 1/4 OF SW 1/4 OF SEC
TR	ROBERT G. CHOQUETTE, SR. REVOCABLE TRUST	Highlands	FL	06/21/2010	2242	1901	22-35S-29E	E 15' OF LOT 13, BLK 5, MAP OF SUBURBAN TRACTS & FARMS OF DESOTO CITY, PRINTS BOOK 20
TR	TIITF	Orange	FL	07/19/2010	10076	8799	06-22S-28E	A PORTION OF WEST ORANGE TRAIL IN SE 1/4 SEC 6 & 50' STRIP OF LAND IN SE 1/4 SEC 6 22S-28E; A PORTION OF WEST ORANGE TRAIL LYING IN THE SW 1/4 SEC 6 22S-28E; SEE EXHIBIT A - AERIAL CROSSING OF BIKE TRAIL

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TR	HINDE, STANLEY E.	Marion	FL	08/06/2010	5394	1597	04-17S-24E	THAT PORTION OF NAUD AVE LYING BETWEEN LOT 198 & LOT 184 ACCORDING TO THE MAP OF WEIR PARK AS RECORDED IN PLAT BOOK E, PAGE 45
TR	CITRUS COUNTY	Citrus	FL	08/12/2010	2370	1836	25-17S-18E	A PORTION OF LANDS DESCRIBED IN OFFICIAL RECORD BOOK 277, PAGES 733 THOUGH 735, INCLUSIVE OF THE PUBLIC RECORDS OF CITRUS COUNTY, SAID LANDS LYING IN SEC
TR	UNDERHILL LLC	Orange	FL	08/19/2010	10091	8835	30-22S-31E	A 20' WIDE STRIP OF LAND ALONG THE SOUTH BOUNDARY OF THE PARENT TRACT
TR	ORANGE COUNTY BOCC	Orange	FL	08/30/2010	10096	9213	28-21S-28E 32-21S-28E 33-21S-28E 34-21S-28E	A PORTION OF LAND GENERALLY 50 FEET IN WIDTH LYING IN THE NW 1/4 SEC 34, NE 1/4 & NW 1/4 SEC 33, NE 1/4 SEC 32, ALL IN 21S-28E SEE EASEMENT
D	WAUGH, LILLIAN	Citrus	FL	09/16/2010	2377	255	29-18S-18E	THE W 330 FT OF THE N 660 FT OF THE NE 1/4 OF THE NE 1/4 OF SEC
D	K. B. LEMIEUX, LLLP, A FLORIDA LIMITED PARTNERSHIP	Orange	FL	09/17/2010	10106	506	06-21S-28E	A PORTION OF LOT 4, SUPERIOR COMMERCE PARK REPLAY NO. 1, AS RECORDED IN PLAT BOOK 60 PAGES 143 THROUGH 144, PUBLIC RECORDS OF ORANGE COUNTY, FLORIDA, LYING IN SEC.
TR	NEW DESTINY CHRISTIAN CENTER CHURCH INC.	Orange	FL	09/17/2010	10106	325	34-21S-28E	SEE EXHIBIT A - A 10' X 270' EASEMENT AREA - W 10' OF S 270' OF NE4 OF NW4 IN SEC 34-21S-28E
TR	CITY OF PINELLAS PARK, FLORIDA	Pinellas	FL	09/23/2010	17037	2576	27-30S-16E	ALL THAT PORTION OF THE VACATED 82ND AVE N, 83RD AVE N & 34TH ST N LYING WITHIN THE EXISTING 150' TX R/W THROUGH GOLDEN ACRES SUBD IN NE 1/4 OF NE 1/4 SEC. SEE DOCUMENT FOR METES & BOUNDS DESCRIPTION.
TR	STEVENS, MYRTLE C. (CONNER)	Polk	FL	09/29/2010	8228	1007	35-29S-25E	W 17 A. OF SW 1/4 OF SE 1/4 & 2 A. IN SW COR OF NW 1/4 OF SE 1/4
TR	CITY OF OLDSMAR, FLORIDA	Pinellas	FL	10/28/2010	17071	1225	14-28S-16E	THAT PORTION OF A 60.40 FOOT UNNAMED ROAD RIGHT-OF-WAY (A/K/A BAYVIEW BLVD N) LYING BETWEEN BLOCK 208 AND BLOCK 211 OF THE REVISED MAP OF OLDSMAR AS RECORDED IN PLAT BOOK 7, PAGE 6 AND LYING WITHIN THE 100 FOOT FLORIDA POWER CORPORATION TRANSMISSION RIGHT-OF-WAY ESTABLISHED BY EASEMENTS RECORDED IN DEED BOOK 1286, PAGES 4 AND 22, ALL BEING RECORDED IN THE PUBLIC RECORDS OF PINELLAS COUNTY, FLORIDA/ WHICH RIGHT-OF-WAY IS BEING VACATED CONTEMPORANEOUSLY HEREWITH, SEE EXHIBIT A

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TR	BRANTLEY, ROBERT J CO-TRUSTEE	Orange	FL	11/08/2010	10130	7998	22-22S-31E	FOUR 20' PARCELS AKA AS TRACT 3, 4 , 5 AND 6, HOOVER RD, ORANGE COUNTY
D	W.T. PAUL LIAU, INDIVIDUALLY AND AS TRUSTEE	Polk	FL	11/09/2010	8255	662	06-26S-28E	THAT PART OF THE NE 1/4 OF THE SW 1/4 OF SEC AND THAT PART OF THE N 1/2 OF THE NW 1/4 OF THE SW 1/4 OF SEC
TR	ST. JOE TIMBERLAND COMPANY OF DELAWARE, L.L.C.	Franklin	FL	12/10/2010	1032	481	34-06S-03W	COMMENCE AT THE NE CORNER OF SEC.
D	ST. JOE TIMBERLAND COMPANY OF DELAWARE, L.L.C.	Franklin	FL	12/10/2010	1025	334	34-06S-03W	COMMENCE AT THE NE CORNER OF SEC.
TR	PASCO COUNTY	Pasco	FL	12/14/2010	8485	740	30-26S-16E	COMMENCE AT THE NE CORNER OF THE NW 1/4 OF SEC
D	MARKS, SANDRA B.	Franklin	FL	12/17/2010	1025	593	02-09S-08W	LEGAL DESCRIPTION FURNISHED BY PARTIES AND NOT VERIFIED BY DRAFTOR.
D	MARKS, C.A.	Franklin	FL	12/17/2010	1025	598	02-09S-08W	COMMENCE AT THE NE CORNER OF SEC.
D	MARKS, SANDRA B.	Franklin	FL	12/17/2010	1025	596	02-09S-08W	COMMENCE AT THE NE CORNER OF SEC.
TR	REEDY CREEK IMPROVEMENT DISTRICT	Orange	FL	12/20/2010	10148	9182	08-24S-27E 21-24S-27E	THE EAST 70 FEET OF THE RCID PARCEL ADJACENT TO THE WEST BOUNDARY OF SR 429.
TR	PEAVEY, LAVERNE C	Orange	FL	12/20/2010	10148	9180	23-22S-27E	THE NORTH TEN FEET (10) OF THE WEST THREE FEET (3) OF LOT 1, M.C. BRITT SUBDIVISION NO. 1, ACCORDING TO THE PLAT THEREOF AS RECORDED IN PLAT BOOK K, PAGE 145, PUBLIC RECORDS OF ORANGE COUNTY, FLORIDA.
TR	CITY OF WINTER GARDEN	Orange	FL	12/20/2010	10148	9203	32-21S-28E	SOUTHWEST QUARTER OR SECTION 32 TOWNSHIP 21, SOUTH, RANGE 28 EAST

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TR	REEDY CREEK IMPROVEMENT DISTRICT	Orange	FL	12/20/2010	10148	9182	08-24S-27E 16-24S-27E 21-24S-27E	THE EAST 70 FEET OF THE RCID PARCEL ADJACENT TO THE WEST BOUNDARY OF SR 429.
D	HUGHES, JEANNETTE	Polk	FL	12/23/2010	8286	755	07-26S-28E 12-26S-28E	LOT 8, 9, 10, 11 AND 19, BLOCK D, ROY A. MILLER'S SUBDIVISION, ACCORDING TO THE MAP OR PLAT THEREOF AS RECORDED IN PLAT BOOK 32, PAGE 50, PUBLIC RECORDS OF POLK COUNTY, FLORIDA, LESS AND EXCEPT THAT PART OF LOT 19 DESCRIBED AS FOLLOWS: FROM THE SE CORNER OF LOT 19
D	AUERBACH, STUART	Orange	FL	12/27/2010	10150	4366	26-22S-32E	LOT 10, BLOCK 2, CHRISTMAS GARDENS NO. 1,
TR	ROBERT G. CHOQUETTE, SR., TRUSTEE	Highlands	FL	12/29/2010	2266	400	22-35S-29E	A PORTION OF LAKE FRONT DRIVE LYING NORTH OF LOT 13, BLK K,TOWN OF DESOTO CITY, PRINTS BOOK 20; SEE EXHIBIT "A"; ROAD IS BEING VACATED
TR	ORLANDO-ORANGE COUNTY EXPRESSWAY AUTHORITY	Orange	FL	01/06/2011	10155	8594	06-22S-28E32-21S-28E	A 50' WIDE EASEMENT ALONG THE WEST PROPERTY LINE PARCEL "A" . A 50' WIDE EASEMENT ALONG THE EAST AND SOUTH PROPERTY LINE OF PARCEL "B". A 30' WIDE EASEMENT ALONG THE NORTH PROPERTY LINE OF PARCEL "C".
TR	BOARD OF TRUSTESS OF THE INTERNAL IMPROVEMENT TRUST FUND	Levy	FL	01/18/2011	1222	16	06-17S-17E	A PARCEL OF LAND LYING IN THE S 1/2 OF SEC
TR	15022 OLD CHENEY, LLC, A FLORIDA LIMITED LIABILITY COMPANY	Orange	FL	01/25/2011	10154	1596	19-22S-32E	THE NORTH 50' OF THE PARENT TRACT SOUTH AND WEST OF OLD CHENEY HWY.
TR	LEMERY, MATTHEW RYAN	Levy	FL	02/14/2011	1224	326	01-12S-15E	SEE EXHIBIT A (SKETCH & LEGAL) - A 14 ACRE TRACT IN E2 OF E2 OF NE4 - 01-12S-15E
TR	BUIE, BEVERLY	Levy	FL	02/14/2011	1224	329	04-12S-15E	W 689.94' OF NW4 OF NE4 LESS RD ROW OF 04-12S-15E - SEE EXHIBIT A
TR	YUNKER, JAMES C	Levy	FL	02/14/2011	1224	332	03-12S-15E	SEE EXHIBIT A (SKETCH & LEGAL) - TRACT IN N2 OF 03-12S-15E
TR	WHITAKER JR, CECIL E	Levy	FL	02/14/2011	1224	335	03-12S-15E	W2 OF W2 OF NW4 OF NE4 LESS W 50 FT & LESS N 60 FT & LESS ADDN RD R/W - SEE EXHIBIT A (SKETCH & LEGAL)

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TR	LEMERY, JR CARL F.	Levy	FL	02/14/2011	1224	344	01-12S-15E	SEE EXHIBIT A (SKETCH & LEGAL) - E2 OF E2 OF NE4 LESS RD R/W
TR	HAMBERGER, KACEY N	Levy	FL	02/14/2011	1224	341	04-12S-15E	SEE EXHIBIT A (SKETCH & LEGAL) - 2.52 AC TRACT IN NE4 OF NE4 & 4.60 AC TRACT IN NE4 OF NE4 ALL IN 04-12S-15E; BRONSON-CHIEFLAND NEW 69KV LINE
TR	TILLIS, MELBA H	Levy	FL	02/14/2011	1224	338	05-12S-16E	SEE EXHIBIT A SKETCH AND LEGAL - A 30FT X 30FT STRIP OF LAND IN SEC. 5-12S-16E; SEE EXHIBIT A (SKETCH & LEGAL) - W 30 FT. OF E2 OF E2 OF N2 IN 05-12S-16E
TR	JUDY, CHARLES E	Levy	FL	02/14/2011	1224	347	02-12S-16E	SEE EXHIBIT A (SKETCH & LEGAL) - A 7.88 ACRE TRACT IN THE N2 OF 02-12S-16E
TR	MARTINEZ, SALLY TEADT	Levy	FL	03/04/2011	1226	24	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 03-12S-15E TRACT BEING 1266 FT X 367 FT IN NE 1/4 A/K/A LOT 1 LEVYVILLE ACRES
TR	JACKSON, DAVID H.	Levy	FL	03/04/2011	1226	21	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 03-12S-15E EAST 340.17 FT OF W2 OF NE4 OF NE4
TR	COGGINS, DENNIS E.	Levy	FL	03/04/2011	1226	18	01-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 01-12S-15E - W2 OF E2 OF NE4 LESS ROAD R/W
TR	LIGHTHOUSE WORD MINISTRIES INCORPORATED	Levy	FL	03/04/2011	1226	14	04-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 04-12S-15E 10.34 X 13 CHAINS IN NW4 OF NE4
TR	SMITH JAMES H	Levy	FL	03/14/2011	1226	851	05-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 05-12S-15E- NE4 OF NE4
TR	VICTOR GALEONE AS BISHOP OF THE DIOCESE OF SAINT AUGUSTINE	Levy	FL	03/14/2011	1226	854	06-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 06-12S-15E - NE4 OF NE4 OF NE4
D	RAMNATH, MOTEELALL	Citrus	FL	03/21/2011	2409	1966	20-17S-17E	A PARCEL OF LAND LYING IN THE SW 1/4 OF SEC

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D	NINJA INVESTMENTS LTD., A FLORIDA LIMITED PARTNERSHIP	Citrus	FL	03/21/2011	2409	1960	29-17S-17E	A PARCEL OF LAND LYING IN THE NE 1/4 OF THE NW ¼
D	FLORIDA STERLING INVESTMENTS, LTD A FLORIDA LIMITED PARTNERSHIP	Citrus	FL	03/21/2011	2409	1980	29-17S-17E	A PARCEL OF LAND LYING IN THE NE 1/4 OF THE NW 1/4 OF SEC
D	MILES, JR., R. STEPHEN, INDIVIDUALLY AND AS TRUSTEE	Citrus	FL	03/21/2011	2409	1970	29-17S-17E	A PARCEL OF LAND LYING IN THE NE 1/4 OF THE NW 1/4 OF SEC
TR	UNITED STATES OF AMERICA	Sumter	FL	03/24/2011	2298	562	09-20S-27E	SECTION 9 TOWNSHIP 20 RANGE 23
TR	LOUIS RAGANELLA AND ROSEMARY RAGANELLA CO-TRUSTEES OR THEIR SUCCESSORS IN TRUST UNDER THE LOUIS RAGANELLA TRUST DATED SEP 11 2009	Orange	FL	04/01/2011	10193	4995	23-22S-31E	SEE EXHIBIT A (SKETCH & LEGAL) - W4 OF SW4 OF NW4 LESS ROAD R/W AND OTHER IN 23-22S-31E
TR	CHUCK HOLLOW, INC.	Orange	FL	04/01/2011	10193	5002	23-22S-31E	SEE EXHIBIT A (SKETCH & LEGAL) - W4 OF SW4 OF NW4 LESS ROAD R/W AND OTHER IN 23-22S-31E
TR	APALACHICOLA BAY CHARTER SCHOOL INC.	Franklin	FL	04/01/2011	1032	453	02-09S-08W	THE SOUTH 70' OF THE PARENT TRACT
TR	FRANKLIN COUNTY BOARD OF COUNTY COMMISSIONERS	Franklin	FL	04/01/2011	1032	457	01-09S-08W 02-09S-08W 10-09S-08W 11-09S-08W	A 30' STRIP OF LAND ADJACENT TO THE NORTH BOUNDARY OF HWY 98, AND A 70' WIDE STRIP OF LAND ALONG THE SOUTH AND EAST BOUNDARIES OF THEIR PARCEL ADJACENT TO
TR	HUDSON, JAMES HERSCHIEL JR.	Levy	FL	04/01/2011	1228	474	31-11S-15E	SEE EXHIBIT A SKETCH & LEGAL - PART OF NE4 OF SW4 LYING SOUTHERLY & WESTERLY OF US HWY 27
TR	DONALDSON, JOHN H.	Levy	FL	04/01/2011	1228	477	04-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - 04-12S-15E - NE CORNER OF NE4 OF NE4
TR	LOUIS RAGANELLA AND ROSEMARY RAGANELLA CO-TRUSTEES OR THEIR SUCCESSORS IN TRUST UNDER THE LOUIS RAGANELLA TRUST DATED SEP 11 2009	Orange	FL	4/1/2011	10193	4995	23-22S-31E	SEE EXHIBIT A (SKETCH & LEGAL) - W4 OF SW4 OF NW4 LESS ROAD R/W AND OTHER IN 23-22S-31E

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TR	CHUCK HOLLOW, INC.	Orange	FL	4/1/2011	10193	5002	23-22S-31E	SEE EXHIBIT A (SKETCH & LEGAL) - W4 OF SW4 OF NW4 LESS ROAD R/W AND OTHER IN 23-22S-31E
TR	HELLER BROS. PACKING CORP. A FLORIDA CORPORATION, SUCCESSOR BY MERGER TO PACIFIC PACKING COMPANY	Polk	FL	04/19/2011	8369	2207	18-26S-27E	THE EAST 20' OF THE PARENT TRACT ADJACENT TO HWY 27 R/W
TR	THE PANTRY, INC., A DELAWARE CORPORATION, SUCCESSOR BY MERGER TO LIL' CHAMP FOOD STORES, INC., SUCCESSOR BY MERGER TO MILLER ENTERPRISES, INC.	Polk	FL	04/19/2011	8369	2211	01-26S-27E	THE NORTH 20' OF THE PARENT TRACT SOUTH OF CR 54
TR	SMITH-BEAUCHAMP PARTNERSHIP	Levy	FL	04/21/2011	1230	314	01-12S-15E 02-12S-15E	SEE EXIBIT A (SKETCH & DESCRIPTION) - N2 & N2 OF S2 IN 02-12S-15E AND NW4 & N2 OF SW4 IN 01-12S-15E
TR	ENGLISH, ARTHUR	Levy	FL	04/21/2011	1230	319	04-12S-15E	SEE EXHIBIT A SKETCH & DESCRIPTION - N 918 FT OF W 252.07 FT. OF EAST 1206.04 FT OF NE4 OF NE4 LESS N 60 FT FOR R/W OF US 27 ALT IN 04-12S-15E
TR	HUDSON, JAMES ROLLIN JR.	Levy	FL	04/21/2011	1230	322	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - E2 OF NW4 LESS R/W FOR US 27 ALT IN 03-12S-15E
TR	HUDSON, JAMES ROLLIN JR.	Levy	FL	04/21/2011	1230	325	05-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - NW4 OF NW4 OF NE4 LESS R/W FOR US 27 ALT. IN 05-12S-15E
TR	HUDSON FARMS, INC., A FLORIDA CORPORATION	Levy	FL	04/21/2011	1230	328	05-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - NW4 OF NW4 & NE4 OF NW4 & NW4 OF NE4 LESS R/W OF US 27 ALT IN 05-12S-15E
TR	EAGLE FL I SPE, LLC, A NORTH CAROLINA LIMITED LIABILITY COMPANY	Hernando	FL	04/25/2011	2818	899	32-22S-19E	NORTH 25 FT OF THE EAST 300 FT OF E2 OF FRACTIONAL SE4 IN SEC. 32-T22S-R19E SEE EXHIBIT A SKETCH AND LEGAL
TR	ANDREWS, A D	Levy	FL	04/28/2011	1230	912	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - NW4 OF NW4 OF NW4 LESS RD R/W IN 03-12S-15E
TR	JONES, DAVID J.	Levy	FL	05/13/2011	1232	208	04-12S-15E	THE NORTH 30' OF THE PARENT TRACT SOUTH OF ALT HWY 27 R/W

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TR	SANDERS, DONALD	Franklin	FL	05/13/2011	1034	712	01-09S-08W	SEE EXHIBIT A SKETCH & LEGAL - 01-09S-08W - A 22.23 EASEMENT ALONG NORTH P/L CONTIGUOUS TO FRED MEYER STREET R/W
TR	SHELTON, ROBERT D	Levy	FL	05/16/2011	1232	310	04-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - N2 OF NE4 OF NW4 IN SEC 04-12S-15E LESS ROAD R/W
TR	HUTTO, CHARLES	Levy	FL	05/16/2011	1232	313	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - E2 OF W2 OF NW4 OF NE4 SEC 03-12S-15E LESS ROAD R/W
TR	SWANN, MARGARET GAINES REVOCABLE TRUST DATED FEB 17 1998	Orange	FL	05/16/2011	10214	3726	12-22S-29E	SEE EXHIBIT A SKETCH & LEGAL - LOTS 1 & 2, LAWNDALE THIRD ADDITION PER PLAT BOOK L PAGE 95 ORANGE COUNTY FLORIDA RECORDS - LYING IN NE4 OF NW4 IN SEC 12-22S-29E
TR	GRAY, J CHARLES	Volusia	FL	05/16/2011	6592	2806	03-22S-30E	SEE EXHIBIT A SKETCH & LEGAL - WEST 250' OF SW4 NORTH OF DIRKSEN ROAD IN SEC 03-19S-30E
D	ST. JOE TIMBERLAND COMPANY OF DELAWARE, LLC	Franklin	FL	5/18/2011	1035	56	02-9S-8W	SW CORNER OF THE SW QUARTER OF SECTION 2, TOWNSHIP 9 SOUTH, RANGE 8 WEST
TR	CENTRECORP INC	Polk	FL	05/19/2011	8391	148	06-26S-27E	SEE EXHIBT A SKETCH & LEGAL - PARCEL IN NW4 OF SEC 6-26S-27E
TR	TAYLOR, CHARLES S	Hernando	FL	06/01/2011	2825	913	33-22S-18E	SEE EXHIBIT A - A STRIP 295FT WIDE IN SE1/4 OF SE1/4 IN SEC 33-22S-18E
TR	LOTT, STEADMON RICHARD	Citrus	FL	06/03/2011	2423	198	29-18S-18E	50' X 50' IN SW CORNER OF PARCEL IN (APPROX.) NW 1/4 OF SW 1/4 OF SW 1/4
TR	LEWIS, MAE M.	Citrus	FL	06/03/2011	2423	194	29-18S-18E	SW 1/4 OF SW 1/4 OF SW 1/4 (APPROX.)
D	HERRERA, MAYRA, INDIVIDAULLY AND AS TRUSTEE	Citrus	FL	6/10/2011	2424	448	20-17S-17E	LOT NUMBER 2 OF BLOCK 3, CRYSTAL MANOR UNIT NO. 1

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D	G.A.M.E. INVESTMENTS , INC.	Citrus	FL	6/10/2011	2424	440	20-17S-17E	LOT NUMBER 19 OF BLOCK 12, CRYSTAL MANOR UNIT NO. 1
D	SPILLSON, NICK LOUIS	Citrus	FL	6/10/2011	2424	436	20-17S-17E	LOT NUMBER 2 OF BLOCK 15, CRYSTAL MANOR UNIT NO. 1
D	HELPING HANDS MINISTRIES, INC.	Citrus	FL	6/10/2011	2424	445	20-17S-17E	LOT NUMBER 7 OF BLOCK 132, CRYSTAL MANOR UNIT NO. 3
D	SWANSON, SCOTT	Citrus	FL	6/10/2011	2424	431	18-17S-17E	LOT NUMBER 4 OF BLOCK 132, CRYSTAL MANOR UNIT NO. 3; LOT NUMBER 2 OF CRYSTAL MANOR UNIT 1A; LOT NUMBER 1 OF CRYSTAL MANOR UNIT 1A
TR	DE LOS SANTOS, ANTONIO	Levy	FL	06/16/2011	1234	761	03-12S-15E	NE4 OF NW4 OF NW4 LESS ROAD R/W IN SEC. 03-12S-15E
TR	GRAHAM, MARK LAINE	Levy	FL	06/16/2011	1234	757	04-12S-15E	NW4 OF NW4 LESS ROAD R/W IN SEC. 04-12S-15E
TR	FOUR CORNERS GROUP LLC	Polk	FL	06/20/2011	8412	998	01-26S-26E 06-26S-27E	THE NORTH 20' OF THE PARENT TRACT SOUTH OF CR 54
TR	SPILLANE, JACK E.	Levy	FL	06/23/2011	1235	512	01-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - W2 OF NE4 LESS ROAD R/W IN SEC. 01-12S-15E
D	MILES, R STEPHEN INDIVIDUALLY AND AS TRUSTEE	Citrus	FL	06/27/2011	2426	1710	29-17S-17E	A PARCEL OF LAND LYING IN THE NE 1/4 OF THE NW 1/4 OF SEC
D	MILES, JR STEPHEN INDIVIDUALLY AND AS TRUSTEE	Citrus	FL	6/27/2011	2426	1710	29-17S-17E	A PARCEL OF LAND LYING IN THE NORTHEAST 1/4 OF THE NORTHWEST 1/4 OF SECTION 29, TOWNSHIP 17 SOUTH, RANGE 17 EAST, CITRUS COUNTY, FLORIDA, AND BEING ALL OF LOT NUMBER 3 OF THE UNRECORDED PLAT OF CRYSTAL GARDENS ; A PARCEL OF LAND LYING IN THE NORTHEAST 1/4 OF THE NORTHWEST 1/4 OF SECTION 29, TOWNSHIP 17 SOUTH, RANGE 17 EAST, CITRUS COUNTY, FLORIDA, AND BEING ALL OF LOT NUMBER 5 OF THE UNRECORDED PLAT OF CRYSTAL GARDENS; AND A PARCEL OF LAND LYING IN THE NORTHEAST 1/4 OF THE NORTHWEST 1/4 OF SECTION 29, TOWNSHIP 17 SOUTH, RANGE 17 EAST, CITRUS COUNTY, FLORIDA, AND BEING ALL OF LOT NUMBER 7 OF THE UNRECORDED PLAT OF CRYSTAL GARDENS AS REFERENCED IN OFFICIAL RECORDS BOOK 580, PAGE 1072

Doc Type	Grantor	County	State	Record Date	Deed Book	Deed Page	Section Township Range	Notes
TR	CITY OF TALLAHASSEE	Wakulla	FL	06/26/2011	855	179	26-03S-01E	COM AT A LITEWOOD HUB MARKING THE SW COR OF SEC
TR	MARION COUNTY	Marion	FL	6/28/2011	5535	1457	28-22S-31E	THAT PORTION OF THE NW ¼ OF THE NW ¼ OF SW ¼ EXCEPT THE NORTH 209.88' OF THE WEST 331' AS RECORDED IN OR 3008/399-400 OF THE PUBLIC RECORDS OF MARION COUNTY, FLORIDA LYING WITHIN THE EXISTING 100 FOOT TRANSMISSION RIGHT-OF-WAY AS MORE PARTICULARLY DESCRIBED IN SCHEDULE "A"
TR	SCHOOL BOARD OF MARION COUNTY, FL	Marion	FL	6/28/2011	5535	1454	03-12S-15E	THAT PORTION OF THE NORTH 209.88' OF THE WEST 331' OF THE NW¼ OF THE SW¼ LYING WITHIN THE EXISTING 100' TRANSMISSION RIGHT-OF-WAY. FOR MOS FACILITIES
TR	SOLOMON CHAPEL UNITED METHODIST CHURCH	Marion	FL	6/28/2011	5535	1450	26-03S-01E	THAT PORTION OF THE NORTH 209.88' OF THE WEST 331' OF THE NW¼ OF THE SW¼ LYING WITHIN THE EXISTING 100' TRANSMISSION RIGHT-OF-WAY. FOR MOS FACILITIES
TR	FAIRCLOTH, JASON K	Levy	FL	07/08/2011	1236	636	03-12S-15E	SEE EXHIBIT A SKETCH & LEGAL - NE2 OF NE4 OF NE4 LESS ROAD R/W IN SEC. 03-12S-15E
TR	SANLANDO PROPERTY HOLDINGS, LLC	Orange	FL	07/15/2011	10240	826	28-22S-31E	SEE EXHIBIT A SKETCH & LEGAL - PARCEL IN SEC 28-22S-31E
D	SEDWICK, ROGER L.	Citrus	FL	7/18/2011	2430	569	20-17S-17E	LOT NUMBER 4 OF BLOCK 4, CRYSTAL MANOR UNIT NO. 1; LOT NUMBER 5 OF BLOCK 4, CRYSTAL MANOR UNIT NO. 1
D	FRANCIS, JOSEPH A. AND HAZEL	Citrus	FL	7/18/2011	2430	571	18-17S-17E	LOT NUMBER 8 OF BLOCK 134, CRYSTAL MANOR UNIT NO. 3
D	BENNETT, DONALD W. AND SHARON V.	Citrus	FL	7/18/2011	2430	575	18-17S-17E	LOT NUMBER 14 OF BLOCK 130, CRYSTAL MANOR UNIT NO. 3; LOT NUMBER 18 OF BLOCK 115, CRYSTAL MANOR UNIT NO. 2
D	PERRY, VAUGHN DWIGHT AND DIANE L.	Citrus	FL	7/18/2011	2430	573	20-17S-17E	LOT NUMBER 10 OF BLOCK 125, CRYSTAL MANOR UNIT NO. 2
D	MATTHEWS, GEORGE AND KAREN	Citrus	FL	7/18/2011	2430	580	20-17S-17E	LOT NUMBER 18 OF BLOCK 115, CRYSTAL MANOR UNIT NO. 2; LOT NUMBER 14 OF BLOCK 130, CRYSTAL MANOR UNIT NO. 3

Doc Type	Grantor	County	State	Record Date	Deed Book	Deed Page	Section Township Range	Notes
D	MARONDA HOMES, INC.	Citrus	FL	7/18/2011	2430	578	20-17S-17E	LOT NUMBER 10 OF BLOCK 115, CRYSTAL MANOR UNIT NO. 2; LOT NUMBER 9 OF BLOCK 115, CRYSTAL MANOR UNIT NO. 2
D	FINESTINE, NORMAN AND CINDY	Citrus	FL	7/20/2011	2430	1529	20-17S-17E	LOT NUMBER 8 OF BLOCK 8, CRYSTAL MANOR UNIT NO. 1
D	CHALDYSHEV, ANDREY AND ROZA	Citrus	FL	7/20/2011	2430	1547	20-17S-17E	LOT NUMBERS 11 AND 12 OF BLOCK 8, CRYSTAL MANOR UNIT NO. 1
D	NEWMAN, SELMA	Citrus	FL	7/20/2011	2430	1545	18-17S-17E	LOT NUMBER 7 OF BLOCK 133, CRYSTAL MANOR UNIT NO. 3
D	SHUEY, JR. JACK T. AND CHAROLYN SHULTZ	Citrus	FL	7/20/2011	2430	1531	18-17S-17E	LOT NUMBER 3 OF BLOCK 3, CRYSTAL MANOR UNIT NO. 1
D	GRAHAM, FRANK M. AND ELINOR R.	Citrus	FL	8/4/2011	2433	237	20-17S-17E	LOT NUMBER 11 OF BLOCK 115, CRYSTAL MANOR UNIT NO. 2

EXHIBIT (2)-a

SMITH, ANDERSON, BLOUNT,
DORSETT, MITCHELL & JERNIGAN, L.L.P.

OFFICES
2500 Wachovia Capitol Center
Raleigh, North Carolina 27601

LAWYERS

MAILING ADDRESS
P.O. Box 2611
Raleigh, North Carolina
27602-2611

TELEPHONE: (919) 821-1220
FACSIMILE: (919) 821-6800

August 18, 2011

Barclays Capital Inc.
Citigroup Global Markets Inc.
Goldman, Sachs & Co.
Mitsubishi UFJ Securities (USA), Inc.
SunTrust Robinson Humphrey, Inc.
KeyBanc Capital Markets Inc.
The Williams Capital Group, L.P.

c/o Barclays Capital Inc.
745 Seventh Avenue
New York, New York 10019
Attention: Syndicate Registration

and

Citigroup Global Markets Inc.
388 Greenwich Street
New York, New York 10013
Attention: General Counsel

and

Goldman, Sachs & Co.
200 West Street
New York, New York 10282
Attention: Registration Department

Re: Florida Power Corporation d/b/a Progress Energy Florida, Inc. / $300,000,000 First Mortgage Bonds, 3.10% Series due 2021

Ladies and Gentlemen:

We have acted as counsel to Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company"), in connection with the issuance (the "Transaction") of $300,000,000 aggregate principal amount of the Company's First Mortgage Bonds, 3.10% Series due 2021 (the "Securities"), under the Company's Indenture dated as of January 1, 1944, between the Company

and The Bank of New York Mellon, as successor trustee, as amended and supplemented to and including the date hereof, including by the Fiftieth Supplemental Indenture dated as of August 18, 2011 (as so amended and supplemented, the "Mortgage"). This opinion is furnished to you at the Company's request pursuant to Section 9(c) of the Underwriting Agreement dated August 15, 2011 (the "Underwriting Agreement"), among the Company and Barclays Capital Inc., Citigroup Global Markets Inc., and Goldman, Sachs & Co., each as an Underwriter and as a Representative of the Underwriters named in Schedule I to the Underwriting Agreement, pursuant to which the Securities are being sold. Capitalized terms used and not defined herein shall have the meanings assigned to them in the Underwriting Agreement.

We have reviewed such documents and considered such matters of law and fact as we, in our professional judgment, have deemed necessary to render the opinions contained herein. The documents reviewed included, among others:

i. The Company's registration statement on Form S-3 (No. 333-155418-01) filed under the Securities Act of 1933, as amended (the "Securities Act");

ii. The prospectus dated November 18, 2008 (together with the documents incorporated therein by reference, the "Base Prospectus"), as supplemented by the preliminary prospectus supplement dated August 15, 2011, filed pursuant to Rule 424(b) of the Securities Act (the Base Prospectus, as supplemented by such preliminary prospectus supplement, the "Preliminary Prospectus"), pursuant to which the Securities were offered;

iii. The prospectus supplement dated August 15, 2011, filed pursuant to Rule 424(b) of the Securities Act (the Base Prospectus, as supplemented by such prospectus supplement, the "Prospectus");

iv. The Permitted Free Writing Prospectus;

v. The Mortgage;

vi. The form of the Securities; and

vii. The Underwriting Agreement.

Where we have considered it appropriate, with respect to certain facts, we have relied, without investigation or analysis of any underlying data contained therein, upon (i) certificates or other comparable documents of public officials, and (ii) certificates of officers or other appropriate representatives of the Company. In addition, we have also examined originals or

copies, certified to our satisfaction, of the documents and agreements listed in certificates signed by duly authorized officers of the Company dated as of the date hereof.

The opinions set forth herein are limited to matters governed by the federal laws of the United States, and we express no opinion as to the laws of any other jurisdiction. This opinion letter has been prepared in accordance with the customary practice of lawyers who regularly give and lawyers who regularly advise recipients regarding opinion letters of this kind. This opinion letter shall be interpreted in accordance with Statement on the Role of Customary Practice in the Preparation and Understanding of Third-Party Legal Opinions as published in 63 Business Lawyer 1277 (2008) and the Legal Opinion Principles issued by the Committee on Legal Opinions of the American Bar Association's Section of Business Law as published in 53 Business Lawyer 831 (1998).

Based upon and subject to the foregoing and the further assumptions, limitations and qualifications herein expressed, it is our opinion that:

1. The Mortgage has been duly qualified under the Trust Indenture Act of 1939, as amended.

2. The statements made in the Base Prospectus under the caption "Description of First Mortgage Bonds" and in the Preliminary Prospectus and the Prospectus under the caption "Description of Bonds," insofar as they purport to constitute summaries of the documents referred to therein, are accurate in all material respects.

3. The statements made in the Preliminary Prospectus and the Prospectus under the caption "Material U.S. Federal Tax Considerations," insofar as they purport to constitute summaries of matters of U.S. federal income tax law or legal conclusions with respect thereto, are accurate and complete in all material respects.

This opinion letter is delivered solely for your benefit (individually and as Representatives, as applicable) in connection with the Transaction and may not be used or relied upon by any other person or for any other purpose without our prior written consent in each instance. Our opinions herein are expressed as of the date hereof, and we undertake no obligation to advise you of changes in applicable law or any other matters that may come to our attention after the date hereof that may affect our opinions expressed herein.

To ensure compliance with U.S. Treasury Department Circular 230, you are hereby notified that: (a) any discussion of federal tax issues in this opinion letter is not intended or written to be relied upon, and cannot be relied upon, by any taxpayer for the purpose of avoiding penalties that may be imposed on taxpayers under the Internal Revenue Code;

(b) such discussion is included in this opinion letter in connection with the promotion or marketing (within the meaning of Treasury Department Circular 230) of the transactions or matters addressed in this opinion letter; and (c) each taxpayer should seek advice based on its particular circumstances from an independent tax advisor.

Very truly yours,

SMITH, ANDERSON, BLOUNT, DORSETT,
MITCHELL & JERNIGAN, L.L.P.

Smith, Anderson, Blount, Dorsett,
Mitchell, & Jernigan, L.L.P.

EXHIBIT (2)-b

Progress Energy

(Writer's Direct Dial No. 727-820-5587)

R. ALEXANDER GLENN
General Counsel

August 18, 2011

Barclays Capital Inc.
Citigroup Global Markets Inc.
Goldman, Sachs & Co.
Mitsubishi UFJ Securities (USA), Inc.
SunTrust Robinson Humphrey, Inc.
KeyBanc Capital Markets Inc.
The Williams Capital Group, L.P.

c/o Barclays Capital Inc.
745 Seventh Avenue
New York, New York 10019
Attention: Syndicate Registration

and

Citigroup Global Markets Inc.
388 Greenwich Street
New York, New York 10013
Attention: General Counsel

and

Goldman, Sachs & Co.
200 West Street
New York, New York 10282
Attention: Registration Department

Re: Florida Power Corporation d/b/a Progress Energy Florida, Inc. / $300,000,000 First Mortgage Bonds, 3.10% Series due 2021

Ladies and Gentlemen:

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

As General Counsel of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company"), I am familiar with the terms and provisions of the Underwriting Agreement dated August 15, 2011 (the "Underwriting Agreement") among the Company and Barclays Capital Inc., Citigroup Global Markets Inc. and Goldman, Sachs & Co., each as an Underwriter and as a Representative of the Underwriters named in Schedule I of the Underwriting Agreement, providing for the purchase by the Underwriters of $300,000,000 aggregate principal amount of the Company's First Mortgage Bonds, 3.10% Series due 2021 (the "Securities"), to be issued under the Company's Indenture dated as of January 1, 1944 (the "Mortgage") between the Company and The Bank of New York Mellon, as successor trustee (the "Trustee"), as amended and supplemented by fifty indentures supplemental thereto, including the Forty-Ninth Supplemental Indenture dated as of March 1, 2010 (the "Forty-Ninth Supplemental Indenture"), and the Fiftieth Supplemental Indenture dated as of August 18, 2011 ("Fiftieth Supplemental Indenture"). This opinion is furnished to you at the Company's request pursuant to Section 9(d) of the Underwriting Agreement. Capitalized terms used and not defined herein shall have the meanings assigned to them in the Underwriting Agreement.

In connection with the foregoing, I have examined the following:

a. The Company's registration statement on Form S-3 (No. 333-155418-01) filed under the Securities Act of 1933, as amended (the "Securities Act");

b. The prospectus, dated November 18, 2008 (together with the documents incorporated therein by reference, the "Base Prospectus"), as supplemented by the preliminary prospectus supplement, dated August 15, 2011, filed pursuant to Rule 424(b) of the Securities Act (the Base Prospectus, as supplemented by such preliminary prospectus supplement, the "Preliminary Prospectus"), pursuant to which the Securities were offered;

c. The prospectus supplement, dated August 15, 2011, filed pursuant to Rule 424(b) of the Securities Act (the Base Prospectus, as supplemented by such prospectus supplement, the "Prospectus");

d. The final term sheet, dated August 15, 2011, filed pursuant to Rule 433 of the Securities Act (together with the Preliminary Prospectus, the "Pricing Disclosure Package");

e. The Mortgage, including the Fiftieth Supplemental Indenture;

f. The form of the Securities; and

g. The Underwriting Agreement.

As to factual matters, I have relied upon certificates of public officials. I have participated in or reviewed all corporate proceedings with respect to the issuance and sale of the Securities. Whenever the phrase "to my knowledge" is used herein, it refers to the actual knowledge of me or of attorneys employed by the Company and working under my direct supervision.

I call your attention to the fact that neither the Mortgage nor the form of the Securities contains a provision specifying the law by which it is to be governed. For the purposes of the opinions expressed in paragraphs 1 and 2 below, I have assumed that the Mortgage and the Securities will be governed by the laws of the State of Florida. The opinions expressed in paragraph 4 below as to incorporation, valid existence and active status, as the case may be, of the Company are based solely on certificates of legal existence and/or standing issued by the Secretary of State or other appropriate officials of the State of Florida, and my opinion with respect to such matters are rendered as of the respective dates of such certificates and limited accordingly.

Based on the foregoing, my familiarity with the properties and affairs of the Company generally, and such other information and documents as I have considered necessary for the purposes hereof, I am of the opinion that:

1. The Mortgage has been duly and validly authorized by all necessary corporate action, has been duly and validly executed and delivered by the Company and is a valid and binding mortgage of the Company enforceable in accordance with its terms, except as limited by bankruptcy, insolvency or other laws affecting mortgagees' and other creditors' rights and general equitable principles and any implied covenant of good faith and fair dealing; provided, however, that certain remedies, waivers and other provisions of the Mortgage may not be enforceable, but such unenforceability will not render the Mortgage invalid as a whole or affect the judicial enforcement of (i) the obligation of the Company to repay the principal of the Securities, together with the interest thereon as provided in the Securities or (ii) the right of the Trustee to exercise its right to foreclose under the Mortgage.

2. Assuming authentication of the Securities by the Trustee in accordance with the Mortgage and delivery of the Securities to and payment for the Securities by the Underwriters, as provided in the Underwriting Agreement, the Securities have been duly and validly authorized, executed and delivered and are legal, valid and binding obligations of the Company enforceable in accordance with their terms, except as limited by bankruptcy, insolvency or other laws affecting mortgagees' and other creditors' rights and general equitable principles and any implied covenant of good faith and fair dealings, are entitled to the benefits of the security afforded by the Mortgage, and, upon recording of the security interests (i) in all recording offices in the State of Florida in which the property intended to be subject to the lien of the Mortgage is located, (ii) with the Office of the Secretary of State of the State of Florida and (iii) with the Surface Transportation Board, will be secured equally and ratably with all other bonds outstanding under the Mortgage except insofar as any sinking or other fund may afford additional security for the bonds of any particular series.

3. The Underwriting Agreement has been duly and validly authorized, executed and delivered by the Company.

4. The Company has been incorporated and is validly existing as a corporation, and its status is active, under the laws of the State of Florida.

5. The Company is duly authorized by its Restated Articles of Incorporation (the "Charter") to conduct the business that it is now conducting as set forth in the Pricing Disclosure Package and the Prospectus.

6. The Company is an electrical utility engaged in the business of generating, transmitting, distributing and selling electric power to the general public in the State of Florida.

7. The Company has valid and subsisting franchises, licenses and permits adequate for the conduct of its business, except where the failure to hold such franchises, licenses and permits would not have a material adverse effect on the business, properties, results of operations or financial condition of the Company.

8. The Company has good and marketable title, with minor exceptions, restrictions and reservations in conveyances, and defects that are of the nature ordinarily found in properties of similar character and magnitude and that, in my opinion, will not in any substantial way impair the security afforded by the Mortgage, to all the properties described in the granting clauses of the Mortgage and upon which the Mortgage purports to create a lien. The description in the Mortgage of the above-mentioned properties is legally sufficient to constitute the Mortgage a lien upon said properties, including without limitation properties hereafter acquired by the Company (other than those expressly excepted and reserved therefrom). Said properties constitute substantially all the permanent physical properties and franchises (other than those expressly excepted and reserved from the lien of the Mortgage) of the Company and are held by the Company free and clear of all liens and encumbrances except the lien of the Mortgage and excepted encumbrances, as defined in the Mortgage. The properties of the Company are subject to liens for current taxes, which it is the general practice of the Company to pay regularly as and when due. The Company has easements for rights-of-way adequate for the operation and maintenance of its transmission and distribution lines that are not constructed upon public highways. The Company has followed the practice generally of acquiring (i) certain rights-of-way and easements and certain small parcels of fee property appurtenant thereto and for use in conjunction therewith and (ii) certain other properties of small or inconsequential value, without an examination of title and, as to the title to lands affected by said rights-of-way and easements, of not examining the title of the lessor or grantor whenever the lands affected by such rights-of-way and easements are not of such substantial value as in the opinion of the Company to justify the expense attendant upon examination of titles in connection therewith. In my opinion, such practice of the Company is consistent with sound economic practice and with the method followed by other companies engaged in the same business and is reasonably adequate to assure the Company of good and marketable title to all such property acquired by it. It is my opinion that any such conditions or defects as may be covered by the above recited exceptions are not

substantial and would not materially interfere with the Company's use of such properties or with its business operations. The Company has the right of eminent domain in the State of Florida under which it may, if necessary, perfect or obtain title to privately owned land or acquire easements or rights-of-way required for use or used by the Company in its public utility operations.

9. The Mortgage (except for the Fiftieth Supplemental Indenture) has been recorded and filed in such manner and in such places as may be required by law in order fully to preserve and protect, in all material respects, the security of the bondholders and all rights of the Trustee thereunder; and the Fiftieth Supplemental Indenture is in proper form for filing for record, both as a real estate mortgage and as a security interest, in all counties in the State of Florida in which any of the property (except as any therein or in the Mortgage are expressly excepted) described therein or in the Mortgage as subject to the lien of the Mortgage is located and, as a security interest, with the Surface Transportation Board and, upon such recording, the Fiftieth Supplemental Indenture will constitute adequate record notice to perfect the lien of the Mortgage, and preserve and protect, in all material respects, the security of the bondholders and all rights of the Trustee, as to all mortgaged and pledged property acquired by the Company subsequent to the recording of the Forty-Ninth Supplemental Indenture and prior to the recording of the Fiftieth Supplemental Indenture.

10. The Mortgage constitutes a valid, direct and first mortgage lien of record upon all franchises and properties now owned by the Company (other than those expressly excepted from the lien of the Mortgage and other than those franchises and properties which are not, individually or in the aggregate, material to the Company or the security afforded by the Mortgage) situated in the State of Florida, as described or referred to in the granting clauses of the Mortgage, subject to the exceptions as to bankruptcy, insolvency and other laws stated in paragraph 1 above.

11. The issuance and sale of the Securities have been duly authorized by all necessary corporate action on the part of the Company.

12. An order has been entered by the Florida Public Service Commission authorizing the issuance and sale of the Securities, and to my knowledge, said order is still in force and effect; and no further filing with, approval, authorization, consent or other order of any public board or body (except such as have been obtained under the Securities Act and as may be required under the state securities or blue sky laws of any jurisdiction) is legally required for the consummation of the transactions contemplated in the Underwriting Agreement.

13. Except as described in or contemplated by the Pricing Disclosure Package and the Prospectus, there are no pending actions, suits or proceedings (regulatory or otherwise) against the Company or any of its properties that are likely, in the aggregate, to result in any material adverse change in the business, properties, results of operations or financial condition of the Company or that are likely, in the aggregate, to materially and adversely affect the Mortgage,

the Securities or the consummation of the Underwriting Agreement, or the transactions contemplated therein.

14. The consummation of the transactions contemplated by the Underwriting Agreement and the fulfillment of the terms of the Underwriting Agreement will not (i) result in a breach of any of the terms or provisions of, or constitute a default under, the Charter or the Company's by-laws or (ii) result in a breach of any terms or provisions of, or constitute a default under, any applicable law, indenture, mortgage, deed of trust or other material agreement or instrument to which the Company is now a party or any judgment, order, writ or decree of any government or governmental authority or agency or court having jurisdiction over the Company or any of its assets, properties or operations that, in the case of any such breach or default, would have a material adverse effect on the business, properties, results of operations or financial condition of the Company.

[The remainder of this page has been intentionally left blank]

This opinion letter is delivered solely for your benefit (individually and as Representatives, as applicable) in connection with the issuance of the Securities and may not be used or relied upon by any other person or for any other purpose without my prior written consent in each instance. My opinions herein are expressed as of the date hereof, and I undertake no obligation to advise you of changes in applicable law or any other matters that may come to my attention after the date hereof that may affect my opinions expressed herein.

Respectfully submitted,

R. Alexander Glenn
General Counsel

EXHIBIT (3)-a

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, 2011

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 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	(X)	No	( )
PEF	Yes	(X)	No	( )

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

Progress Energy	( )
PEC	( )
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, 2011, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $14,107,388,747. As of June 30, 2011, 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, 2011, 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, 2012, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	295,219,128
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 2012 Annual Meeting of Shareholders are incorporated by reference into PART III, Items 10, 11, 12, 13 and 14 hereof. If such proxy statements are not filed with the SEC within 120 days after the end of our fiscal year, such information will be filed as part of an amendment to the Annual Report on Form 10-K/A.

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. Neither of PEC nor PEF make any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

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" to indicate that certain 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
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASLB	Atomic Safety and Licensing Board
the Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
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, fuel and other pass-through revenues and refunds, if any
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCRC	Capacity Cost-Recovery Clause
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Clean Smokestacks Act	North Carolina Clean Smokestacks Act
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 No. 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 No. 5 coal-fired steam turbines
CSAPR	Cross-State Air Pollution Rule
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
DOJ	United States Department of Justice
DSM	Demand-side management
Duke Energy	Duke Energy Corporation
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
EE	Energy efficiency
EGU MACT	MACT standards for coal-fired and oil-fired electric steam generating units
EIP	Equity Incentive Plan

EPA	United States Environmental Protection Agency
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
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Global	U.S. Global, 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
the Merger	Proposed merger between Progress Energy and Duke Energy
the Merger Agreement	Agreement and Plan of Merger, dated as of January 8, 2011, by and among Progress Energy and Duke Energy
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
NO_2	Nitrogen dioxide
North Carolina Global Case	*Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC*
NOx	Nitrogen oxides
NRC	Nuclear Regulatory Commission
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
Ongoing Earnings	Non-GAAP financial measure defined as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges
OPEB	Postretirement benefits other than pensions
ORS	South Carolina Office of Regulatory Staff
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
PPACA	Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act
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
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REPS	Renewable energy portfolio standard
the Registration Statement	The registration statement filed on Form S-4 by Duke Energy related to the Merger
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
RSU	Restricted stock unit
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 45K	Section 45K of the Code
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
SO_2	Sulfur dioxide
SOx	Sulfur oxides
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
VSP	Voluntary severance plan
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) "Merger" about the proposed merger between Progress Energy and Duke Energy Corporation (Duke Energy) (the Merger) and the impact of the Merger on our strategy and liquidity; b) "Strategy" about our future strategy and goals; c) "Results of Operations" about trends and uncertainties; d) "Liquidity and Capital Resources" about operating cash flows, future liquidity requirements and estimated capital expenditures; and e) "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:

- our ability to obtain the approvals required to complete the Merger and the impact of compliance with material restrictions or conditions potentially imposed by our regulators;
- the risk that the Merger is terminated prior to completion and results in significant transaction costs to us;
- our ability to achieve the anticipated results and benefits of the Merger;
- the impact of business uncertainties and contractual restrictions while the Merger is pending;
- the scope of necessary repairs of the delamination of PEF's Crystal River Unit No. 3 Nuclear Plant (CR3) could prove more extensive than is currently identified, such repairs could prove not to be feasible, the costs of repair and/or replacement power could exceed our estimates and insurance coverage or may not be recoverable through the regulatory process;
- 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, cyber security threats and other catastrophic events;
- 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, safety, 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 should be read carefully. 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, PEC and PEF. 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).

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

The Utilities have 23,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. 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. 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.

For the year ended December 31, 2011, our consolidated revenues were $8.907 billion and our consolidated assets at year-end were $35.059 billion.

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 Investor Relations section of our website at www.progress-energy.com. Information on our website is not incorporated herein and should not be deemed part of this Report. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished with, 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 website, www.sec.gov, containing reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

RECENT DEVELOPMENTS

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the Merger Agreement), which expires on July 8, 2012. Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction and become a wholly owned subsidiary of Duke Energy (the Merger). Both companies' shareholders have approved the Merger. However, consummation of the Merger is subject to customary conditions, including, among other things, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approval, to the extent required, from the Federal Energy Regulatory Commission

(FERC), the Federal Communications Commission, the Nuclear Regulatory Commission (NRC), the North Carolina Utilities Commission (NCUC), the Kentucky Public Service Commission and the South Carolina Public Service Commission (SCPSC). Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required. See Item 1A, "Risk Factors," MD&A – "Introduction – Merger," and Note 2 for additional information related to the Merger.

On February 22, 2012, the Florida Public Service Commission (FPSC) approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The agreement, which will continue through the last billing cycle of December 2016, addresses three principal matters: cost recovery for PEF's proposed Levy Nuclear Power Plant (Levy), the CR3 delamination prudence review pending before the FPSC and certain base rate issues. The agreement sets the Levy cost-recovery factor at a fixed amount during the term of the settlement and also allows PEF to recover investment and replacement power costs for CR3 in various circumstances. The parties to the agreement have waived or limited their rights to challenge the prudence of various costs related to CR3. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current return on equity (ROE) range of 9.5 percent to 11.5 percent. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. Additionally, PEF will refund $288 million to customers through the fuel clause over four years, beginning in 2013. See Note 8C for additional provisions of the 2012 settlement agreement.

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete of the outer wall of the containment building, which resulted in an extension of the outage. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. See "Nuclear Matters – CR3 Outage" and Note 8C.

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.

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 $4.1 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 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 its 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.

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.

In February 2007, the FERC adopted final rules making extensive changes to the pro forma open access transmission tariff (OATT) to ensure that transmission service is provided in a fair manner to all transmission customers. PEC's and PEF's compliance filings reflecting the required changes in the transmission planning areas were approved by the FERC in 2010. Although this final rule impacted the Utilities' transmission operations, planning and wholesale marketing functions, it did not have a significant impact on the Utilities' financial results.

In July 2011, the FERC adopted additional final rules related to regional and interregional transmission planning and cost allocation. These rules also require that the transmission planning process provides a structure whereby a non-incumbent transmission developer could be considered for building transmission projects that are selected for regional or interregional cost allocation. Public utility transmission providers are required to submit compliance filings addressing the regional requirements of the rule by October 2012 and are required to submit compliance filings addressing the interregional requirements of the rule by April 2013. The rule will require significant changes in the PEC and PEF regional and interregional transmission planning and cost allocation approaches, however, based on a preliminary assessment of the rule, it is not expected to have a significant impact on the Utilities' financial results.

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 making market-based sales outside of its control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. PEF likewise made comparable filings which restrict PEF to making market-based rates outside of peninsular Florida and outside of the PEC 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 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 rate decision.

FRANCHISE MATTERS

PEC has non-exclusive 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 PEC's 240 franchises, the majority covers 60-year periods from the date enacted, and 45 have no specific expiration dates. Of the PEC franchise agreements with expiration dates, 11 expire during the period 2012 through 2016, and the remaining agreements expire between 2017 and 2071. We anticipate renewing substantially all of the expiring franchise agreements. To the extent that PEC does not renew the expiring franchise agreements, PEC will continue to operate within municipal rights of way pursuant to statutory authority. 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 non-exclusive franchises with varying expiration dates in 113 of the Florida municipalities in which it distributes electricity. PEF also provides service to eight 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 PEF franchise agreements cover periods ranging from 10- to 30-year periods from the date enacted. Of PEF's 113 franchise agreements, 25 expire between 2012 and 2016, and the remaining agreements expire between 2017 and 2040. We anticipate renewing substantially all of the expiring franchise agreements. To the extent that PEF does not renew the expiring franchise agreements, PEF will continue to operate within municipal rights of way in compliance with city permitting processes that govern these activities.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

The Parent is a registered public utility holding company subject to regulation by the FERC, including provisions relating to the establishment of intercompany extensions of credit, sales, acquisitions of securities and utility assets, and services performed by PESC. 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 United States 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 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 electric 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 electric system in the future, it could have a material adverse effect on our financial condition, results of operations and liquidity.

PEC and PEF have self-reported to the SERC and Florida Reliability Coordinating Council, respectively, noncompliances and violations with the voluntary and mandatory standards from time to time. The noncompliances and violations have led to the development and implementation of mitigation plans at the Utilities. 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.

Nuclear Regulation

The Utilities' nuclear generating units are regulated by the NRC. 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 Regulation

The Utilities are also subject to regulation by federal, state and local regulatory agencies. See "Environmental."

STATE REGULATION

PEC is subject to regulation in North Carolina by the NCUC, and in South Carolina by the 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 authorizes 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 ROE of 12.75 percent.

In PEF's 2010 settlement agreement approved by the FPSC, the FPSC authorized PEF the opportunity to earn a ROE of up to 11.5 percent. The 2010 settlement agreement is in effect through the last billing cycle of 2012. See "Recent Developments" for discussion regarding the 2012 settlement agreement.

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, are as follows:

- *North Carolina Retail* – fuel costs, the fuel and other portions of purchased power (capacity costs for purchases from dispatchable QFs are also recoverable), costs of new demand-side management (DSM) and energy efficiency (EE) 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, and costs of new DSM and EE 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) compliance costs, and 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. PEF is obligated to file for a midcourse recovery between annual fuel hearings in the event its estimated over- or under-recovery of fuel costs meets or exceeds a threshold of 10 percent of estimated total retail fuel revenues and, accordingly, has the ability to mitigate the cash flow impacts due to the timing of recovery of fuel and purchased power costs.

Renewable Energy and Energy-Efficiency Standards

PEC is allowed to recover the costs of DSM and EE programs in North Carolina and South Carolina through an annual DSM and EE clause in each jurisdiction. PEC is allowed to capitalize DSM and EE costs intended to produce future benefits. In addition, the NCUC and the SCPSC have approved other forms of financial incentives for DSM and EE programs, including the recovery of net lost revenues and a performance incentive. 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. EE programs include any equipment, physical or program change implemented after January 1, 2007, that results in less energy used to perform the same function. PEC has implemented a series of DSM and EE programs and will continue to pursue additional programs, which must be approved by the respective utility commissions. We cannot predict the outcome of DSM and EE filings currently pending approval or whether the implemented programs will produce the expected operational and economic results.

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. PEC is on track to meet the 3 percent of retail electric sales target in 2012. PEC has worked diligently to meet the set aside requirements in NC REPS, however, our ability to do so is contingent upon developers meeting proposed project sizes and timelines. In the event that PEC is unable to meet any of the NC REPS set-aside requirements, PEC will seek to modify or delay the set-aside provisions as permitted by the NCUC. 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, regardless of the actual renewables generated or purchased. The NCUC has the 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. The Florida legislature has not taken action on a renewable portfolio standard rule. 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 and prudent compliance costs.

On July 26, 2011, the FPSC voted to set PEF's DSM compliance goals to remain at their current level until the next goal setting docket is initiated. An intervener filed a protest to the FPSC's Proposed Agency Action order, asserting legal challenges to the order. The parties made legal arguments to the FPSC and the FPSC issued an order denying the protest on December 22, 2011. The intervener then filed a notice of appeal of this order to the Florida Supreme Court on January 17, 2012. We cannot predict the outcome of this matter.

See Note 8 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, Shearon Harris Nuclear Plant (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, CR3. 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, when 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. The NRC's remaining open items in the license renewal review process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

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 safe, timely and accurate manner. Any potential impact to company operations could vary and would be dependent upon the nature of the requirement(s).

CR3 OUTAGE

Over time, PEC and PEF have made various modifications to 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 (or separation) within the concrete of the outer wall of the containment building, which resulted in an extension of the outage. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. The preliminary cost estimate for the repair, as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion. PEF will update the current estimate as this work is completed. Under this repair plan, we estimate CR3 will return to service in 2014. Nuclear safety remains our top priority, and our plans and actions will continue to reflect that commitment. The decision related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to the cost of repair and the likelihood of obtaining NRC approval to restart CR3 after repair. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis, and other developments. PEF maintains insurance coverage through the Nuclear Electric Insurance Limited's (NEIL) accidental property damage program, and PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. See Note 8C.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on new nuclear construction, we continue to take steps to keep open the option of building one or more plants. During 2008, PEC and PEF filed combined license (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 PEF's potential construction at 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 that is supportive of nuclear projects.

LEVY

In 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 2008, the FPSC issued a final order granting PEF's petition for a Determination of Need for Levy. In 2009, the Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy site certification that 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 July 30, 2008, PEF filed its COL application with the NRC for two reactors, which was docketed, or accepted for review, by the NRC on October 6, 2008. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. The NRC review and development of the Final Safety Evaluation Report and Final Environmental Impact Statement is expected to be complete in April 2012, which will be followed by mandatory and contested hearings. 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. The Atomic Safety and Licensing Board (ASLB) admitted one contention regarding potential impacts to wetlands from groundwater use and the potential impact of salt drift from cooling tower operation. Under the current schedule, mandatory and contested hearings are expected to be complete by late 2012, with a combined license issued in 2013. We cannot predict the outcome of this matter.

PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. PEF's initial schedule anticipated performing certain site work pursuant to the Limited Work Authorization prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the scope of the Limited Work Authorization 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 projected in-service dates for Units No. 1 and No. 2 of June 2016 and June 2017, respectively, included in the petition for a Determination of Need. Subsequent changes in regulatory and economic conditions have resulted in additional schedule shifts. These conditions include the permitting and licensing process, national and state economic conditions, short-term natural gas prices, and other FPSC decisions. Uncertainty regarding PEF's access to capital on reasonable terms, its ability to secure joint owners and increasing uncertainty surrounding carbon regulation and its costs could be other factors to affect the Levy schedule.

As disclosed in PEF's 2011 nuclear cost-recovery filing, the schedule shifts will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates (See Note 8C). PEF will postpone major construction activities on the project until after the NRC issues the COL, which is expected to be in 2013 if the current licensing schedule remains on track. The schedule shifts will also allow more time for certainty around federal climate change policy. 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. Taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification, we consider Levy to be PEF's

preferred baseload generation option. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, public, regulatory and political support; adequate financial cost-recovery mechanisms; adequate levels of joint owner participation; customer rate impacts; project feasibility, including comparison to other generation options, DSM and EE programs; and availability and terms of capital financing. If the licensing schedule remains on track and if the decision to build is made, the first of the two proposed units could be in service in 2021. The second unit could be in service 18 months later.

PEF signed an engineering, procurement and construction (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 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. PEF executed an amendment to the EPC agreement in 2010 due to the schedule shifts previously discussed. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges.

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 included 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. PEF's 2011 nuclear cost-recovery filing included an updated analysis that demonstrated continued feasibility of the Levy project with PEF's then estimated range of total escalated cost, including transmission, of $17.2 billion to $22.5 billion. The filed estimated cost range primarily reflects cost escalation resulting from the schedule shifts. Many factors will affect the total cost of the project and once PEF receives the COL, it will further refine the project timeline and budget. As previously discussed, we will continue to evaluate the Levy project on an ongoing basis.

Florida regulations allow investor-owned utilities such as PEF to recover the retail portion of prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances of a nuclear power plant prior to commercial operation. The costs are recovered on an annual basis through the Capacity Cost-Recovery Clause (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 retail portion of 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 (See Note 8C).

HARRIS

In 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, which the NRC docketed on April 17, 2008. 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 decision to build is made, a new plant would not be online until the middle of the next decade.

PEC's jurisdictions also have laws regarding 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.

SECURITY

The NRC issues orders with regard to security at nuclear plants in response to new or emerging threats. The most recent 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 are in compliance with the requirements outlined in the orders through the use of additional security measures until permanent construction projects are completed in 2012. 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 NUCLEAR FUEL

The Nuclear Waste Policy Act of 1982 (as amended) 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.

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 contracts 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. See Note 22C for information about complaints 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 Yucca Mountain or another facility would leave the DOE open to further claims by utilities.

Until the DOE begins to accept the spent nuclear fuel, the Utilities will continue to safely manage their spent nuclear fuel. 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 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.

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 5C 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 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."

The foundation for Progress Energy's environmental leadership strategy begins with its environmental management system. Under the environmental management system, the Environmental, Health and Safety Performance Council, which is comprised of senior executives, 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. 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.

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 8 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.

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.

The EPA's final rule to regulate coal combustion residuals is expected in 2012. The EPA proposed two options in 2010. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residual management and disposal as hazardous waste. The other option would have the EPA set mandatory performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste (as most states do now). The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized.

AIR 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 expense. Control equipment installed for compliance with then-existing or proposed laws and regulations may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. PEC has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the North Carolina Clean Smokestacks Act (Clean Smokestacks Act). The air quality controls installed to comply with NOx and SO_2 requirements under certain sections of the Clean Air Act and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for NOx and SO_2 for our North Carolina units at PEC. PEF has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the CAIR.

In 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) and the maximum achievable control technology (MACT) standards for coal-fired and oil-fired electric steam generating units (EGU MACT). Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures, and PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance

timeframe for the EGU MACT. The CSAPR, slated to be in effect January 1, 2012, was stayed by court order in late 2011. The final EGU MACT will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. We are continuing to evaluate the impacts of the CSAPR and EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC.

WATER QUALITY

In 2011, the EPA published its proposed regulations for cooling water intake structures at existing power generating, manufacturing and industrial facilities that withdraw more than two million gallons of water per day from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes to comply with Section 316(b) of the Clean Water Act. Several of our generating plants will be subject to these regulations. The final rule is expected in 2012.

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 EPA has announced a schedule for development of a new source performance standard for new and existing fossil fuel-fired electric utility units. Under the schedule, the EPA was to propose the standard by September 30, 2011, and issue the final rule by May 2012. The EPA is now expected to propose the standard in the first quarter of 2012. The full impact of regulation under GHG initiatives and any final legislation, if enacted, 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.

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 generate electricity through our balanced solution strategy. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in our service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and a state-of-the-art power system. We continuously evaluate new generation options to determine if they are cost effective 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 23, 2012, 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. We entered into a new one-year labor contract with the International Brotherhood of Electrical Workers beginning December 2011. 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 23, 2012, PEC and PEF employed approximately 5,500 and 4,000 full-time employees, respectively.

SEASONALITY AND THE IMPACT OF WEATHER

Seasonal differences in the weather affect demand for electricity. The Utilities experience higher demand during the summer and winter months. As a result, our overall operating results may fluctuate substantially on a seasonal basis.

Beyond the impact of seasonality, deviations from normal weather conditions can significantly affect our financial performance. Our residential and commercial customers are most impacted by weather. Industrial customers are less weather sensitive. We define normal weather conditions as the long-term average of actual historical weather conditions. The number of years used to calculate normal weather is determined by management and differs by jurisdiction.

We estimate the impact of weather on our earnings based on the number of customers, temperature variances from a normal condition and the amount of electricity the average residential, commercial and some governmental customers historically demonstrated to use per degree day. Our methodology used to estimate the impact of weather does not and cannot consider all variables that may impact customer response to weather conditions such as humidity and relative temperature changes. The precision of this estimate may also be impacted by applying long-term weather trends to shorter periods.

Degree-day data are used to estimate the energy required to maintain comfortable indoor temperatures based on each day's average temperature. Heating-degree days measure the variation in the weather based on the extent to which the average daily temperature falls below a base temperature, and cooling-degree days measure the variation in weather based on the extent to which the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating-degree day and each degree of temperature above the base temperature counts as one cooling-degree day. PEC's base temperature for heating- and cooling-degree days is 65° Fahrenheit for all customer classes. PEF's base temperatures vary by customer class, ranging from 65° to 70° Fahrenheit for cooling-degree days and 55° to 65° Fahrenheit for heating-degree days.

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, 2011, PEC had a total summer generating capacity (including jointly owned capacity) of 12,958 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, 2011, PEC was providing electric services, retail and wholesale, to approximately 1.5 million customers. Major wholesale power sales customers include North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency (Power Agency) and Public Works Commission of the City of Fayetteville, North Carolina. Major industries in PEC's service area include chemicals, textiles, paper, food, metals, wood products, rubber and plastics and stone products. No single customer accounts for more than 10 percent of PEC's revenues.

PEC's net income available to parent was $513 million, $600 million and $513 million for the years ended December 31, 2011, 2010 and 2009, respectively. PEC's total assets were $16.102 billion, $14.899 billion and $13.502 billion at December 31, 2011, 2010 and 2009, respectively.

REVENUES

See "Electric Utility Regulated Operating Statistics – PEC" for information about energy sales and operating revenues.

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.

See "Electric Utility Regulated Operating Statistics – PEC" for generated and purchased energy supply by source and PEC's average fuel cost.

PEC's total system generation (excluding jointly owned capacity) by primary energy source, along with purchased power for the last three years, is presented in the following table:

	2011	2010	2009
Nuclear	**43 %**	35 %	41 %
Coal	**35 %**	49 %	46 %
Oil/Gas	**13 %**	9 %	6 %
Purchased Power	**8 %**	6 %	6 %
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. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income. 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.

Nuclear

Nuclear fuel is processed through four distinct stages: uranium ore mining and milling, conversion, enrichment and fabrication. PEC has sufficient contracts for each stage 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 – Spent Nuclear Fuel."

Coal

PEC anticipates a burn requirement of approximately 9.6 million tons of coal in 2012. Approximately 88 percent of the coal is expected to be supplied from Central Appalachian, 7 percent from Illinois Basin, and 5 percent from Northern Appalachian coal sources and will be primarily delivered by rail.

For 2012, PEC has short-term, intermediate and long-term agreements from various sources for approximately 98 percent of its estimated burn requirements of its coal units. The contracts have expiration dates ranging from one to seven years. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

As discussed within Note 8B, PEC has implemented a plan to retire certain coal-fired units representing approximately 30 percent of its coal-fired power generation fleet no later than the end of 2013 as part of a major coal-to-gas modernization strategy. See "Oil and Gas" for planned gas facilities.

Oil and Gas

In June 2011, PEC placed in service a newly constructed 600-MW natural gas-fueled combined cycle unit at the Smith Energy Complex in Richmond County, N.C. PEC is in the process of constructing two new generating facilities: an approximately 950-MW combined cycle natural gas-fueled facility at a site in Wayne County, N.C., and an approximately 620-MW natural gas-fueled generating facility at its Sutton coal plant site in New Hanover County, N.C. The facilities have expected in-service dates in January 2013 and December 2013, respectively.

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from various suppliers. PEC uses derivative instruments to limit its exposure to price fluctuations for natural gas. PEC has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEC's physical oil and natural 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 and intrastate pipelines. PEC may also purchase additional shorter-term transportation for its load requirements during peak periods.

Purchased Power

PEC purchased approximately 4.6 million MWh, 4.0 million MWh and 3.3 million MWh of its system energy requirements during 2011, 2010 and 2009, respectively, under purchase obligations and operating leases and had 1,394 MW of firm purchased capacity under contract during 2011. 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 its Tillery and Blewett plants for 50 years and anticipates a decision by the FERC in 2012. 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, 2011, PEF had a total summer generating capacity (including jointly owned capacity) of 10,019 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, 2011, 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, the city of Gainesville, the city of Winter Park and the city of Homestead. 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 and agriculture. No single customer accounts for more than 10 percent of PEF's revenues.

PEF's net income available to parent was $312 million, $451 million and $460 million for the years ended December 31, 2011, 2010 and 2009, respectively. PEF's total assets were $14.484 billion, $14.056 billion and $13.100 billion at December 31, 2011, 2010 and 2009, respectively.

REVENUES

See "Electric Utility Regulated Operating Statistics – PEF" for information about energy sales and operating revenues.

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.

See "Electric Utility Regulated Operating Statistics – PEF" for PEF's energy supply by source and energy fuel cost.

PEF's total system generation (excluding jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

	2011	2010	2009
Oil/Gas	**56 %**	54 %	44 %
Coal	**25 %**	26 %	25 %
Purchased Power	**19 %**	20 %	20 %
Nuclear[(a)]	**- %**	- %	11 %

[(a)] Due to the extended outage at CR3 nuclear generating unit that began in September 2009, no nuclear power was generated in 2011 and 2010.

PEF is generally permitted to pass the cost of fuel and certain purchased power to its customers through fuel cost-recovery clauses. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income. In early 2012, PEF agreed to a settlement returning $288 million to customers through the fuel clause (See Note 8C). 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.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from various suppliers. PEF uses derivative instruments to limit its exposure to price fluctuations for natural gas and oil. PEF has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEF's physical oil and natural 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 may also purchase additional shorter-term transportation for its load requirements during peak periods.

Coal

PEF anticipates a burn requirement of approximately 4.6 million tons of coal in 2012. Approximately 79 percent of the coal is expected to be supplied from the Illinois Basin and 21 percent from Central Appalachian coal sources and will be primarily delivered by water.

For 2012, PEF has intermediate and long-term contracts from various sources for approximately 105 percent of its estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to four years. PEF will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

Purchased Power

PEF purchased approximately 7.8 million MWh, 9.5 million MWh and 8.7 million MWh of its system energy requirements during 2011, 2010 and 2009, respectively, under purchase obligations, operating leases and capital leases and had 2,105 MW of firm purchased capacity under contract during 2011. 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 if required. 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: uranium ore mining and milling, conversion, enrichment and fabrication. PEF has sufficient contracts for each stage 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 – Spent Nuclear Fuel."

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 19 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 $250 million, $195 million and $216 million for the years ended December 31, 2011, 2010 and 2009, respectively. Corporate and Other segment total assets were $20.926 billion, $21.110 billion and $20.538 billion at December 31, 2011, 2010 and 2009, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**33,834**	44,971	40,420	46,771	51,163
Nuclear	**25,059**	21,624	29,412	30,565	30,336
Combustion turbine/combined cycle	**29,259**	27,856	21,254	15,557	13,319
Hydro	**602**	608	651	429	415
Purchased	**12,404**	13,473	11,996	14,956	14,994
Total energy supply (company share)[a]	**101,158**	108,532	103,733	108,278	110,227
Jointly owned share[a] [b]	**5,046**	5,228	5,500	5,780	5,351
Total system energy supply	**106,204**	113,760	109,233	114,058	115,578
Average fuel costs (per million Btu)					
Oil	**$ 14.98**	$ 13.15	$ 11.78	$ 9.60	$ 8.70
Gas	**$ 6.24**	$ 6.92	$ 8.36	$ 10.14	$ 8.67
Coal	**$ 3.73**	$ 3.70	$ 3.85	$ 3.50	$ 3.06
Nuclear	**$ 0.60**	$ 0.59	$ 0.53	$ 0.46	$ 0.45
Weighted-average	**$ 3.55**	$ 3.90	$ 3.79	$ 3.66	$ 3.17
Energy sales (millions of kWh)					
Retail					
Residential	**37,386**	39,632	36,516	36,328	37,112
Commercial	**25,736**	26,080	25,523	26,080	26,215
Industrial	**13,856**	13,884	13,653	15,174	15,721
Other retail	**4,834**	4,860	4,753	4,768	4,805
Unbilled	**(1,226)**	630	491	(107)	(61)
Wholesale	**15,215**	17,856	17,801	21,063	21,333
Total energy sales	**95,801**	102,942	98,737	103,306	105,125
Company uses and losses	**5,357**	5,590	4,996	4,972	5,102
Total energy requirements	**101,158**	108,532	103,733	108,278	110,227
Operating revenues (in millions)					
Retail					
Billed	**$ 8,025**	$ 8,714	$ 8,449	$ 7,585	$ 7,672
Unbilled	**(58)**	28	14	7	1
Wholesale	**880**	1,080	1,114	1,288	1,191
Miscellaneous revenue	**338**	354	301	280	270
Amount to be refunded to customers[c]	**(288)**	-	-	-	-
Total operating revenues of the Utilities	**$ 8,897**	$ 10,176	$ 9,878	$ 9,160	$ 9,134

[a] The extended outage at PEF's CR3 nuclear generating unit that began in September 2009 impacted the energy supply mix in 2011, 2010 and 2009.

[b] Amounts represent joint owners' share of the energy supplied from the six generating facilities that are jointly owned. Replacement power was supplied to the CR3 joint owners in 2011 and 2010 from other generating sources or purchased power.

[c] Amount to be refunded to PEF customers through the fuel clause in accordance with the PEF 2012 settlement agreement (See Note 8C).

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**21,009**	30,528	27,261	28,363	30,770
Nuclear	**25,059**	21,624	24,467	24,140	24,212
Combustion turbine/combined cycle	**7,435**	5,429	3,634	2,795	2,960
Hydro	**602**	608	651	429	415
Purchased	**4,512**	3,985	3,251	4,735	3,901
Total energy supply (company share)	**58,617**	62,174	59,264	60,462	62,258
Jointly owned share[(a)]	**5,046**	5,228	5,057	5,205	4,800
Total system energy supply	**63,663**	67,402	64,321	65,667	67,058
Average fuel costs (per million Btu)					
Oil	**$ 17.85**	$ 14.34	$ 14.84	$ 16.05	$ 12.28
Gas	**$ 5.98**	$ 6.59	$ 8.17	$ 10.66	$ 9.19
Coal	**$ 3.66**	$ 3.56	$ 3.82	$ 3.39	$ 2.96
Nuclear	**$ 0.60**	$ 0.59	$ 0.53	$ 0.46	$ 0.44
Weighted-average	**$ 2.48**	$ 2.69	$ 2.60	$ 2.44	$ 2.21
Energy sales (millions of kWh)					
Retail					
Residential	**18,148**	19,108	17,117	17,000	17,200
Commercial	**13,844**	14,184	13,639	13,941	14,032
Industrial	**10,613**	10,665	10,368	11,388	11,901
Other retail	**1,610**	1,574	1,497	1,466	1,438
Unbilled	**(597)**	172	360	(8)	(55)
Wholesale	**12,605**	13,999	13,966	14,329	15,309
Total energy sales	**56,223**	59,702	56,947	58,116	59,825
Company uses and losses	**2,394**	2,472	2,317	2,346	2,433
Total energy requirements	**58,617**	62,174	59,264	60,462	62,258
Operating revenues (in millions)					
Retail					
Billed	**$ 3,785**	$ 4,044	$ 3,801	$ 3,582	$ 3,534
Unbilled	**(34)**	11	5	8	-
Wholesale	**648**	729	707	737	754
Miscellaneous revenue	**129**	138	114	102	97
Total operating revenues	**$ 4,528**	$ 4,922	$ 4,627	$ 4,429	$ 4,385

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

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2011	2010	2009	2008	2007
Energy supply (millions of kWh)					
Generated					
Steam	**12,825**	14,443	13,159	18,408	20,393
Nuclear	**-**	-	4,945	6,425	6,124
Combustion turbine/combined cycle	**21,824**	22,427	17,620	12,762	10,359
Purchased	**7,892**	9,488	8,745	10,221	11,093
Total energy supply (company share)[a]	**42,541**	46,358	44,469	47,816	47,969
Jointly owned share[a][b]	**-**	-	443	575	551
Total system energy supply	**42,541**	46,358	44,912	48,391	48,520
Average fuel costs (per million Btu)					
Oil	**$ 14.11**	$ 12.96	$ 11.43	$ 9.24	$ 8.54
Gas	**$ 6.33**	$ 7.00	$ 8.40	$ 10.03	$ 8.51
Coal	**$ 3.88**	$ 4.09	$ 4.25	$ 3.74	$ 3.28
Nuclear	**$ -**	$ -	$ 0.52	$ 0.49	$ 0.48
Weighted-average	**$ 5.53**	$ 6.14	$ 5.88	$ 5.67	$ 4.85
Energy sales (millions of kWh)					
Retail					
Residential	**19,238**	20,524	19,399	19,328	19,912
Commercial	**11,892**	11,896	11,884	12,139	12,183
Industrial	**3,243**	3,219	3,285	3,786	3,820
Other retail	**3,224**	3,286	3,256	3,302	3,367
Unbilled	**(629)**	458	131	(99)	(6)
Wholesale	**2,610**	3,857	3,835	6,734	6,024
Total energy sales	**39,578**	43,240	41,790	45,190	45,300
Company uses and losses	**2,963**	3,118	2,679	2,626	2,669
Total energy requirements	**42,541**	46,358	44,469	47,816	47,969
Operating revenues (in millions)					
Retail					
Billed	**$ 4,240**	$ 4,670	$ 4,648	$ 4,003	$ 4,138
Unbilled	**(24)**	17	9	(1)	1
Wholesale	**232**	351	407	551	437
Miscellaneous revenue	**209**	216	187	178	173
Amount to be refunded to customers[c]	**(288)**	-	-	-	-
Total operating revenues	**$ 4,369**	$ 5,254	$ 5,251	$ 4,731	$ 4,749

[a] The extended outage at PEF's CR3 nuclear generating unit that began in September 2009 impacted the energy supply mix in 2011, 2010 and 2009.

[b] Amounts represent joint owners' share of the energy supplied from the two generating facilities that are jointly owned. Replacement power was supplied to the CR3 joint owners in 2011 and 2010 from other generation sources or purchased power.

[c] Amount to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement (See Note 8C).

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 may be unable to obtain the approvals required to complete our merger with Duke Energy or, obtaining required governmental and regulatory approvals may require the combined company to comply with restrictions or conditions that may materially impact the anticipated benefits of the Merger.

On January 8, 2011, we entered into a definitive merger agreement with Duke Energy. Before the Merger may be completed, various filings must be made with certain state and federal regulators, antitrust and other authorities in the United States. See Note 2 for the status of shareholder and regulatory approvals. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the Merger, including restrictions or conditions on the business, operations or financial performance of the combined company following consummation that may materially impact the anticipated benefits of the Merger. These conditions or changes could have the effect of delaying completion of the Merger or imposing additional costs on or limiting the revenues of the combined company following the Merger, which could have a material adverse effect on the financial results of the combined company and/or cause either party to abandon the Merger.

In particular, in response to the FERC's concerns about market power in the Carolinas, we and Duke Energy have prepared a mitigation plan and anticipate filing it with the FERC after review by the NCUC. The mitigation plan contains an interim component involving power sales to new market participants and a permanent component involving construction of transmission upgrades. The companies intend to hold discussions with consumer advocates in an effort to reach agreement concerning state ratemaking treatment associated with the mitigation plan and other merger-related issues. We cannot provide assurances that the FERC will approve the mitigation plan or that the NCUC or SCPSC will approve ratemaking treatment of the components of the plan and other merger-related issues, in each case on terms acceptable to either company. In addition, the companies will have to assess the costs associated with any mitigation plan together with the costs associated with other regulatory approvals in connection with the provisions of the Merger Agreement.

We are also subject to the risk that other required conditions to the Merger may not be satisfied. The Merger is subject to a number of customary closing conditions, including the accuracy of representations and warranties, receipt of legal opinions concerning tax consequences, the absence of legal restraints, and the absence of any material adverse effect with respect to either party. In the event one of these conditions is not satisfied, one or both companies would have the ability to terminate the Merger unless satisfaction of the condition is waived.

In the event that the Merger Agreement is terminated prior to the completion of the Merger, we could incur significant transaction costs that could materially impact our financial performance and results. Failure to complete the Merger could also negatively impact our stock price and our future business and financial results.

We have incurred, and will continue to incur, significant merger transaction costs, including legal, accounting, financial advisory, filing, printing and other costs relating to the Merger. If the Merger is not completed, then the benefit of these costs will be lost. Additionally, if the Merger is not completed, depending upon the reasons for not completing the Merger, including whether we have received or entered into a competing takeover proposal, we may be required to pay Duke Energy a termination fee of $400 million. The costs associated with not completing the Merger could have a material effect on our financial results.

If completed, our merger with Duke Energy may not achieve the anticipated results and benefits.

We and Duke Energy entered into the Merger Agreement with the expectation that the Merger would result in various benefits, including, among other things, cost savings and operating efficiencies primarily relating to the regulated businesses. Achieving the anticipated benefits of the Merger is subject to a number of uncertainties, including whether our businesses and the businesses of Duke Energy can be integrated in an efficient, effective and timely manner. As noted above, as a result of obtaining all necessary regulatory approvals, certain restrictions or conditions may be imposed on the combined company that materially impact or limit the benefits anticipated by us as a result of the Merger. The combined company is also subject to the risk that the expected cost savings and operational synergies may not be fully realized. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected liquidity provided by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial results and prospects.

We will be subject to business uncertainties and contractual restrictions while the merger with Duke Energy is pending that could adversely affect our financial results.

Uncertainty about the effect of the Merger on employees or suppliers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, and could cause suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our business operations and financial results could be adversely affected.

Merger- and integration-related issues will place a significant burden on management and internal resources. The diversion of management time on merger-related issues could affect our financial results.

In addition, the Merger Agreement restricts us, without Duke Energy's consent, from making certain acquisitions and taking other specified actions, including limiting our total capital spending, limiting the extent to which we can obtain financing through long-term debt and equity issuances or increasing the Parent's common stock dividend rate until the Merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to consummation of the Merger or termination of the Merger Agreement. Unless the Merger Agreement is terminated earlier, we and Duke Energy will each have the right to terminate the Merger Agreement if the Merger has not been completed by July 8, 2012.

The scope of necessary repairs of the delamination of CR3 could prove more extensive than is currently identified, such repairs could prove not to be feasible, the costs of repair and/or replacement power could exceed our estimates and insurance coverage or may not be recoverable through the regulatory process; the occurrence of any of which could adversely affect our financial condition, results of operations and cash flows.

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete at the periphery of the containment building, which resulted in an extension of the outage. After analysis, PEF determined that the concrete delamination at CR3 was caused by redistribution of stresses in the containment wall that occurred when PEF created an opening to accommodate the replacement of the unit's steam generators. In March 2011, the work to return the plant to service was suspended after monitoring equipment at the repair site identified a new delamination that occurred in a different section of the outer wall after the repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations

could occur during the repair process. CR3 has remained out of service while PEF conducted an engineering analysis and review of the new delamination and evaluated repair options.

In June 2011, PEF notified the NRC and the FPSC that it plans to repair the CR3 containment structure and estimates it will return CR3 to service in 2014. The repair option selected entails systematically removing and replacing concrete in substantial portions of the containment structure walls. The planned option does not include replacing concrete in the area where concrete was replaced during the initial repair. PEF's preliminary cost estimate for this repair, as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion, although a number of factors will affect the repair schedule, return-to-service date and costs of repair, including regulatory reviews, final engineering designs, contract negotiations, ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. In addition to regulatory reviews, our assessment and plans for recovery of costs and repair of CR3 are being reviewed by Duke Energy. PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, believes that replacement power and repair costs not recoverable through insurance to be recoverable through PEF's fuel cost-recovery clause or base rates.

While the foregoing reflects PEF's current intentions and estimates with respect to CR3, the costs, timing and feasibility of additional repairs to CR3, the cost of replacement power, and the degree of recoverability of these costs, are all subject to significant uncertainties. Additional developments with respect to the condition of the CR3 structures, costs that are greater than anticipated, recoverability that is less than anticipated and/or the inability to return CR3 to service all could adversely affect our financial condition, results of operations and cash flows. See Note 8C for additional information related to the CR3 outage.

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition, results of operations and cash flows.

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, results of operations and cash flows, particularly if the costs of those changes are not fully recoverable from our ratepayers.

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 through cost-recovery clauses of certain additional costs, known as "pass-through" costs, 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.

Regulatory decisions may also impact prospective revenues and earnings, affect the timing of the recognition of revenues and expenses and may overturn past decisions used in determining our revenues and expenses.

Management continually evaluates the anticipated recovery of regulatory assets, liabilities and revenues subject to refund and provides allowances as deemed necessary. In the event that our assessment of the probability of recovery through the ratemaking process is incorrect, we will adjust the associated regulatory asset or liability to reflect the change in our assessment or any regulatory disallowances. A change in our evaluation of the probability of recovery of regulatory assets or a regulatory disallowance of all or a portion of our costs could adversely impact our financial condition, results of operations and cash flows.

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;
- limitations imposed on our nuclear generating units by regulatory agencies or a failure to obtain required licenses for our nuclear generating units, as discussed later;
- 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;
- failure to adequately forecast system requirements and commodity requirements; 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, results of operations and cash flows.

A significant portion of our generating facilities was constructed many years ago. Aging equipment, even if maintained in accordance with industry practices, may require significant capital expenditures. Failure of equipment or facilities could potentially increase O&M expense, purchased power expense and capital expenditures.

A cyber attack could adversely affect our business, financial condition, results of operations and cash flows.

Information security risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication and activities of cyber attacks. Through our smart grid and other initiatives, we have increasingly connected equipment and systems related to the generation, transmission and distribution of electricity to the Internet. Because of the critical nature of our infrastructure and the increased accessibility enabled through connection to the Internet, we may face a heightened risk of cyber attack. In the event of such an attack, we could have our business operations disrupted, property damaged and customer information stolen; experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation and damage to our reputation.

Meeting the anticipated demand in our service territories and fulfilling our environmental compliance strategies will require, among other things, modernization of coal-fired generating facilities, the construction of new generating 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, results of operations and cash flows.

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 power systems 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 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 capacity 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 not to 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. We are implementing our announced plan to retire certain coal-fired units in North Carolina that do not have emission control equipment by the end of 2013 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 generating 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 generating 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. However, because of schedule shifts, we executed an amendment to the EPC agreement and will postpone major construction activities on the project until after the NRC issues the COL. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict the timing of when those obligations will be satisfied or the magnitude of any change. PEF has completed suspension negotiations with the equipment vendors regarding those long lead time equipment items for which work was suspended.

In addition, other COL applicants could 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 GHGs, 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, results of operations and cash flows.

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 3 percent by 2012 and increasing to 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, results of operations and cash flows may be adversely affected.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, safety, 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 has one jointly owned 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 generating 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 financial condition, results of operations and cash flows. 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 construction beginning on a number of new nuclear facilities around the world, and the prospect of several projects across the United States, there will be 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, results of operations and cash flows.

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 residues. 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 financial condition, results of operations and cash flows. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures.

Our compliance with evolving environmental regulations, including those regarding water quality and the reduction of emissions of NOx, SO_2 and mercury from coal-fired power plants, is anticipated to require significant capital expenditures that could impact our financial condition. These costs are anticipated to be eligible for regulatory recovery through either base rates or cost-recovery clauses.

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, results of operations and cash flows. Future legislation or regulations related to climate change may impose significant restrictions on CO_2 and other GHG emissions. We may incur significant costs to comply with such legislation or regulations or in connection with related litigation. 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 condition, results of operations and cash flows if associated costs of control or limitation cannot be recovered from ratepayers.

Potential climate change impacts in the southeastern United States could include warmer days and nights, increased total rainfall from heavy storms, increased severe weather events, 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. As noted below, severe weather may adversely affect our results of operations.

We could become subject to litigation related to the purported impacts of GHG emissions. A number of legal actions have been filed against us and 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 financial condition, results of operations 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. Unusually mild weather could diminish our results of operations and cash flows 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 condition, results of operations and cash flows.

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 condition, results of operations and cash flows could be materially and adversely impacted.

Under its 2010 settlement agreement, PEF is allowed to recover the costs of named storms on an expedited basis through a surcharge on monthly residential customer bills for storm costs. In the event the storm costs exceed the maximum allowed surcharge, which will be eliminated under the 2012 settlement agreement, excess additional costs can be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to a specified level after storm costs are fully recovered.

PEC does not maintain a storm damage reserve account and does not have a cost-recovery clause to recover storm costs. PEC may request recovery of significant storm-related costs; PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over agreed-upon time 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 and 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. Fuel costs are recovered primarily through cost-recovery clauses, subject to the Utilities' state utility commissions' approval. Additionally, 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 an 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;
- production levels of natural gas, crude oil and refined products, nuclear fuel and coal;
- 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 and 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 program; its credit facility; 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 credit 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 credit facility 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 issuances. 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 and cash flows may be adversely impacted.

We typically 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 credit facilities, 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 and 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 typically 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, surety bonds 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 affect our business, financial condition, results of operations and cash flows.

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 condition, results of operations and cash flows. 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 NDT 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 NDT funds and benefit plan assets, our financial condition, results of operations and cash flows could be negatively affected.

Impairment of goodwill could have a significant negative impact on our financial condition, results of operations and cash flows.

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 reporting units, and goodwill impairment tests are performed at the utility reporting unit level.

We calculate the fair value of our utility reporting units 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 Utilities' 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 reporting units 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 earnings under accounting principles generally accepted in the United States of America (GAAP) 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. A full impairment of all of our goodwill would cause us to violate financial or restrictive covenants contained in our indebtedness or other contractual arrangements.

Our ability to fully utilize tax credits may be limited. This risk is not applicable to PEC and PEF.

In accordance with the provisions of Internal Revenue Code Section 29/45K, we have generated tax credits based on the content and quantity of coal-based solid 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. The timing of the utilization can also be impacted by certain substantial changes in ownership, including the Merger. 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 turbine, combined cycle and hydroelectric resources, with a total summer generating capacity of 12,958 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2011, 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	382
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	96.3 [d]	2,417 [c]
Sutton[b]	Wilmington, N.C.	3	1954-1972	Coal	100	575
	Total	16				4,970
NUCLEAR						
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,870 [c]
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900 [c]
Robinson	Hartsville, S.C.	1	1971	Uranium	100	724
	Total	4				3,494
COMBUSTION TURBINE						
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	324
Blewett	Lilesville, N.C.	4	1971	Oil	100	52
Cape Fear	Moncure, N.C.	2	1969	Oil	100	46
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	790
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100	75
Morehead City	Morehead City, N.C.	1	1968	Oil	100	12
Smith[e]	Hamlet, N.C.	5	2001-2002	Gas/Oil	100	820
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	11
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	44				3,185
COMBINED CYCLE						
Smith[e]	Hamlet, N.C.	2	2002-2011	Gas/Oil	100	1,084
	Total	2				1,084
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		81				12,958

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

[b] PEC has announced that it intends to retire these units no later than the end of 2013. See Item I, "Business - 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.

[e] Formerly referred to as "Richmond."

At December 31, 2011, including both the total generating capacity of 12,958 MW and the total firm contracts for purchased power of 1,394 MW, PEC had total capacity resources of approximately 14,352 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, 2011, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500-kilovolt (kV) lines and 3,100 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 70 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 10,019 MW. Of this total, joint owners own approximately 120 MW. On December 31, 2011, 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	2,295
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	129
	Total	9				3,435
COMBINED CYCLE						
Bartow	St. Petersburg, Fla.	1	2009	Gas/Oil	100	1,133
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 TURBINE						
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	638
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	105
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	[b]	982 [c]
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	12
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	155
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	137
University of Florida						
Cogeneration	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,474
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	860 [c] [d]
	Total	1				860
TOTAL		63				10,019

[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 the right for the remainder of the year.

[c] Facilities are jointly owned. The capacities shown include joint owners' share.

[d] Due to the extended outage at the CR3 nuclear generating unit that began in September 2009, no nuclear power was generated in 2011 and 2010 (See Note 8C).

At December 31, 2011, including both the total generating capacity of 10,019 MW and the total firm contracts for purchased power of 2,105 MW, PEF had total capacity resources of approximately 12,124 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, 2011, PEF had approximately 5,100 circuit miles of transmission lines including 200 miles of 500-kV lines and approximately 1,600 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 65 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 Note 22D and are incorporated by reference herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable

EXECUTIVE OFFICERS OF THE REGISTRANTS AT FEBRUARY 28, 2012

Name	Age	Recent Business Experience
William D. Johnson	58	**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., law 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

52 **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. Mr. Corbett 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

57 **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.

Before joining PEF, Mr. Dolan was with Foster Wheeler Energy Corporation, an international engineering and manufacturing firm.

*Michael A. Lewis

49 **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

50 **Executive Vice President, Energy Supply, Progress Energy,** June 2010 to present. In this role, Mr. Lyash oversees Progress Energy's diverse fleet of generating resources, including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he oversees fuel procurement for the generating fleet and power trading operations. He also serves as Executive Vice President, PEC, since August 2009, and PEF, since July 2009. Mr. Lyash previously served as Executive Vice President, Corporate Development, Progress Energy, from July 2009 to June 2010; 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., in a number of management roles. His last position at Brunswick was as Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the NRC between 1984 and 1993 in a number of senior technical and management positions.

John R. McArthur

56 **Executive Vice President, Progress Energy,** September 2008 to present. In this role, Mr. McArthur is responsible for corporate and utility support functions, including Audit Services, Corporate Communications, Corporate Services, External Relations, Human Resources and Legal. He also serves as General Counsel, since April 2010, and previously from 2004 until 2009, and Corporate Secretary, since 2004, of Progress Energy. 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 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. Mr. McArthur 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 he was a partner with the Raleigh, N.C., law 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

52 **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

55 **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. Prior to joining Progress Energy, he was the General Manager of Florida Power & Light Company's St. Lucie Nuclear Plant.

Paula J. Sims	50	**Senior Vice President, Corporate Development and Improvement, Progress Energy,** June 2010 to present. Ms. Sims is responsible for implementing Progress Energy's balanced solution strategy for meeting the future energy needs of its customers. In addition, she oversees program development and construction of new generation projects, renewable energy and efficiency programs, supply chain, information technology and wholesale power operations. Ms. Sims is the executive sponsor for Continuous Business Excellence, Progress Energy's framework for improving processes, efficiency and overall cost management and has responsibility for environmental, health and safety. She also serves as Senior Vice President, PEC and PEF, since April 2006. Ms. Sims previously served as Senior Vice President, Power Operations, PEC and PEF, from July 2007 to June 2010; Senior Vice President, Regulated Services of PEC, 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 GE Aircraft Engines, where she served in a number of engineering, operations and plant management roles for over 15 years.
Jeffrey M. Stone	50	**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	51	**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. Mr. Yates 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 REGISTRANT'S 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 prices for each quarter for the past two years, and the cash dividends declared per share, are as follows:

	High	Low	Dividends Declared
2011			
First Quarter	**$ 46.83**	**$ 42.55**	**$ 0.620**
Second Quarter	**49.03**	**45.20**	**0.620**
Third Quarter	**52.42**	**42.05**	**0.620**
Fourth Quarter	**56.33**	**49.37**	**0.259**
2010			
First Quarter	$ 41.35	$ 37.04	$ 0.620
Second Quarter	40.69	37.13	0.620
Third Quarter	44.82	38.96	0.620
Fourth Quarter	45.61	43.08	0.620

The December 31 closing price of our Common Stock was $56.02 for 2011 and $43.48 for 2010. At February 23, 2012, we had 48,755 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. Additionally, the Merger Agreement restricts our ability, without Duke Energy's consent, to increase the common stock dividend rate until consummation or termination of the Merger Agreement. See MD&A "Introduction – Merger." In the fourth quarter of 2011, the board of directors declared a partial dividend of $0.259 per share in order to align our dividend payment schedule with that of Duke Energy such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy dividend schedule. It is anticipated that the board will maintain this alignment in anticipation of the closing of the Merger during 2012. On January 20, 2012, the Progress Energy board of directors declared a full quarterly dividend of $0.620 per share payable on March 16, 2012, to shareholders of record on February 17, 2012.

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 on their securities in certain limited circumstances (See Notes 10 and 12B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A.

RESTRICTED STOCK UNIT AWARD PAYOUTS

(a) Securities Delivered. On October 17, 2011, December 8, 2011, and December 12, 2011, 1,108 shares, 3,500 shares and 916 shares, respectively, of our common stock were delivered to certain former employees pursuant to the terms of the Progress Energy 2007 Equity Incentive Plans (the EIP) which has been approved by Progress Energy's shareholders. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(b) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(c) Consideration. The restricted stock unit awards were granted to provide an incentive to the former employees to exert their utmost efforts on Progress Energy's behalf and thus enhance our performance while aligning the employees' interest with those of our shareholders.

(d) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, noncontributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

ISSUER PURCHASES OF EQUITY SECURITIES FOR FOURTH QUARTER OF 2011

Period	(a) Total Number of Shares (or Units) Purchased (1) to (5)	(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	409,839	$49.9474	N/A	N/A
November 1 – November 30	478,809	52.3253	N/A	N/A
December 1 – December 31	84,927	54.1318	N/A	N/A
Total	973,575	$51.4819	N/A	N/A

(1) At December 31, 2011, Progress Energy does not have any publicly announced plans or programs to purchase shares of its common stock.

(2) The plan administrator purchased 554,000 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)).

(3) The plan administrator purchased 215,565 shares of our common stock in open-market transactions to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation.

(4) The plan administrator purchased 202,186 shares of our common stock in open-market transactions to meet share delivery obligations under the Progress Energy Investor Plus Plan (IPP).

(5) Progress Energy withheld 1,824 shares of our common stock during the fourth quarter of 2011 to pay taxes due upon the payout of certain Restricted Stock Unit awards pursuant to the terms of the EIP.

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 2011, 2010 and 2009, PEC paid dividends to the Parent totaling the amounts shown in PEC's Consolidated Statements of Changes in Total Equity included in the financial statements in PART II, Item 8. PEC has provisions restricting dividends in certain circumstances (See Notes 10 and 12). 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 2011 and 2010, PEF paid dividends to Florida Progress totaling the amounts shown in PEF's Statements of Changes in Common Stock Equity included in the financial statements in PART II, Item 8. During 2009, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 10 and 12). 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.

PROGESS ENERGY

	Years Ended December 31				
(in millions, except per share data)	**2011**	2010	2009	2008	2007
OPERATING RESULTS					
Operating revenues	**$ 8,907**	$ 10,190	$ 9,885	$ 9,167	$ 9,153
Income from continuing operations	**587**	867	840	778	702
Net income	**582**	863	761	836	496
Net income attributable to controlling interests	**575**	856	757	830	504
PER SHARE DATA					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$ 1.96**	$ 2.96	$ 2.99	$ 2.95	$ 2.70
Net income attributable to controlling interests	**1.94**	2.95	2.71	3.17	1.96
TOTAL ASSETS	**$ 35,059**	$ 33,054	$ 31,236	$ 29,873	$ 26,338
CAPITALIZATION AND DEBT					
Common stock equity	**$ 10,021**	$ 10,023	$ 9,449	$ 8,687	$ 8,395
Noncontrolling interests	**4**	4	6	6	84
Preferred stock of subsidiaries	**93**	93	93	93	93
Long-term debt, net[a]	**11,991**	12,137	12,051	10,659	8,737
Current portion of long-term debt	**950**	505	406	-	877
Short-term debt	**671**	-	140	1,050	201
Capital lease obligations	**211**	221	231	239	247
Total capitalization and debt	**$ 23,941**	$ 22,983	$ 22,376	$ 20,734	$ 18,634
Dividends declared per common share	**$ 2.119** [b]	$ 2.480	$ 2.480	$ 2.465	$ 2.445

(a) Includes long-term debt to affiliated trust of $273 million at December 31, 2011 and 2010, $272 million at December 31, 2009 and 2008 and $271 million at December 31, 2007 (See Note 23).

(b) In the fourth quarter of 2011, the board of directors declared a partial dividend of $0.259 per share in order to align our dividend payment schedule with that of Duke Energy, such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy schedule.

PEC

(in millions)	Years Ended December 31				
	2011	2010	2009	2008	2007
OPERATING RESULTS					
Operating revenues	**$ 4,528**	$ 4,922	$ 4,627	$ 4,429	$ 4,385
Net income	**516**	602	514	534	501
Net income attributable to controlling interests	**516**	603	516	534	501
Net income attributable to parent	**513**	600	513	531	498
TOTAL ASSETS	**$ 16,102**	$ 14,899	$ 13,502	$ 13,165	$ 11,955
CAPITALIZATION AND DEBT					
Common stock equity	**$ 5,088**	$ 5,180	$ 4,657	$ 4,301	$ 3,752
Noncontrolling interests	**-**	-	3	4	4
Preferred stock	**59**	59	59	59	59
Long-term debt, net	**3,693**	3,693	3,703	3,509	3,183
Current portion of long-term debt	**500**	-	6	-	300
Short-term debt[(a)]	**219**	-	-	110	154
Capital lease obligations	**12**	14	15	16	17
Total capitalization and debt	**$ 9,571**	$ 8,946	$ 8,443	$ 7,999	$ 7,469

(a) Includes notes payable to affiliated companies related to the money pool program of $31 million at December 31, 2011, and $154 million at December 31, 2007.

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 MD&A is separately filed by 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 includes financial information prepared in accordance with 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 accompanying financial statements found elsewhere in this report.

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, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative requirements as a separate reportable business segment.

MERGER

On January 8, 2011, Duke Energy and Progress Energy entered into the Merger Agreement. Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction and become a wholly owned subsidiary of Duke Energy. Consummation of the Merger is subject to customary conditions, including, among others things, approval of the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approvals, to the extent required, from the FERC, the Federal Communications Commission, the NRC, the NCUC, the Kentucky Public Service Commission and the SCPSC. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required.

See Item 1A, "Risk Factors," and Note 2 for risks and additional information related to the Merger.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to consummation of the Merger as discussed below. At this time, we do not anticipate modifying our 2012 strategy discussed below but cannot predict the impact consummation of the Merger will have on our long-term strategy. The combined company's expected balance sheet and credit metrics are anticipated to enhance our growth opportunities and strategic options.

We do not expect the Merger to have a significant impact on our cash requirements and sources of liquidity during 2012. Pursuant to the Merger Agreement, only limited equity issuances through certain employee benefit plans and stock option plans are permitted. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through the IPP and/or

employee benefit and stock option plans to support our liquidity requirements. Additionally, the Merger Agreement restricts our ability, without Duke Energy's consent, to increase the common stock dividend rate until consummation or termination of the Merger Agreement. Total capital spending and the extent to which we can obtain financing through long-term debt issuances are also limited.

After consummation of the Merger, Progress Energy intends to cease filing periodic reports with the SEC as soon as practicable. PEC and PEF intend to continue to file periodic reports with the SEC.

Certain substantial changes in ownership of Progress Energy, including the Merger, can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards (See Note 15).

The companies are targeting for the Merger to close during 2012. Until the Merger has received all necessary approvals and has closed, the companies will continue to operate as separate entities. Accordingly, the information presented in this Form 10-K is presented solely for the Progress Registrants on a pre-merger basis.

STRATEGY

Progress Energy is an integrated energy company with two electric utility subsidiaries that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to competitive wholesale markets in the eastern United States. The Utilities have 23,000 MW of regulated generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities.

We are committed to pursuing the successful completion of the Merger with Duke Energy. We believe that the Merger will provide substantial strategic and financial benefits to shareholders, customers and most employees. These benefits include increased financial strength and flexibility, joint dispatch fuel savings for customers in the Carolinas and a larger, more diverse and better-positioned regulated utility business. We are working to address remaining regulatory conditions while preserving the value of the Merger for all of our stakeholders.

We are focused on excelling in the fundamentals of our business including safety, operational excellence and customer service; consistently achieving our financial objectives; maintaining constructive relations with regulators, political leaders and the general public; as well as focusing on strong leadership that fully engages our workforce for high performance. In addition to these fundamentals, we are concentrating on the following four focus areas:

- Achieve effective integration planning and merger approvals
- Improve the performance of our nuclear fleet
- Optimize our balanced solution strategy
- Accelerate Continuous Business Excellence

EFFECTIVE INTEGRATION PLANNING AND MERGER APPROVALS

As more fully discussed in "Merger" we are pursuing the remaining required regulatory approvals for the Merger and have completed the majority of our merger integration processes. Our integration plans take advantage of the strengths of both companies and the best practices in the industry. Maintaining constructive relations with regulators, public leaders and the general public is fundamental to our business, which will be critical for obtaining the remaining merger approvals. Until the Merger closes, Progress Energy and Duke Energy will continue to operate as two entirely separate companies.

IMPROVE NUCLEAR FLEET PERFORMANCE

We continue to implement a comprehensive, multi-year improvement plan designed to strengthen and align the performance of PEC's nuclear fleet. We are committed to raising our nuclear fleet performance to a consistently high level of safety, reliability and value. To do that, we have made a number of organizational changes and have intensified our focus on plant operations, outage planning and execution, and continuous improvement. We are also leveraging the expertise and capabilities of our company as a whole to meet these nuclear fleet objectives. We have taken significant remediation steps to improve performance of PEC's nuclear fleet after a number of unplanned outages in 2010, and the early signs of progress are evident in the results of 2011 operating statistics. The PEC nuclear fleet set a new generation record in 2011 with a capacity factor of 95.2 percent in 2011 compared to 2010's

83.5 percent. The initial implementation of the multi-year improvement plan for Robinson was a particular focus in 2011 and resulted in higher O&M expense, as discussed in "Results of Operations." We anticipate a lesser impact on O&M in subsequent years as we continue implementation of the improvement plan.

We are continuing in our process to resolve the extended outage of CR3. We have taken appropriate actions to maintain the unit's containment in a safe condition throughout the course of the outage. Through the first quarter of 2012, we expect to continue analyzing and refining information related to the engineering, cost and schedule for the repair of CR3. We are continuing to work with our insurers and federal and state regulators. Additional developments with respect to the condition of the CR3 structures, costs that are greater than anticipated, recoverability that is less than anticipated, and/or the inability to return CR3 to service could all adversely affect our financial results and liquidity. As discussed in "Matters Impacting Future Results and Liquidity," the FPSC has approved a comprehensive settlement agreement between PEF and consumer advocates in Florida that addresses recovery of CR3 replacement power and repair costs.

BALANCED SOLUTION STRATEGY

Our three-pronged balanced solution strategy seeks to meet future customer needs and evolving public policy in a way that creates long-term value for our customers and shareholders. Through a combination of investments and initiatives in energy efficiency, alternative and renewable energy and a state-of-the-art power system, we are addressing the challenge facing our industry of meeting demand and new environmental regulations while controlling costs. Expenditures to achieve our balanced solution are anticipated to be recoverable under base rates or cost-recovery mechanisms implemented in our state jurisdictions.

First, our DSM, EE and energy-conservation programs provide customers with incentives for efficiency improvements and include customer education and outreach efforts. In addition, we are a leader in the utility industry in promoting and preparing for plug-in electric vehicles. We operate a research fleet of plug-in vehicles; maintain partnerships with plug-in vehicle automakers including General Motors, Nissan and Ford; and are participating in a number of demonstration and research programs involving plug-in vehicles and the associated charging stations, including solar-powered charging stations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 380 MW of electricity generated from solar, biomass and municipal solid waste sources. The majority of these projects should be online within the next five years. 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. PEC is on track to meet the first of the targets set under North Carolina's renewable energy portfolio standard, 3 percent of retail electric sales in 2012.

Third, we are pursuing numerous options for a state-of-the-art power system. Our objective is to have a diverse, flexible generation portfolio that enables us to provide reliable, affordable power with a smaller environmental footprint. Fleet modernization and a substantial smart grid program will help us meet this objective. We are also keeping our options open to build advanced nuclear plants.

We have made significant progress in the coal-to-gas fleet transition we announced in 2009. Our initial plans were to retire 11 North Carolina coal units that do not have scrubbers by no later than the end of 2017. These smaller, aging units represent approximately 30 percent (or 1,500 MW) of our North Carolina fleet. In 2011, we accelerated the final closure timetable to 2013 and retired the first of the units. To replace the coal-fired generation to be retired, we placed a 600-MW combined-cycle plant in service in mid-2011 and have broken ground on two other plants, which are projected to begin service in 2013. Of our approximately 7,500 MW of coal-fired generation, we have scrubbed and installed emission control equipment on almost 5,000 MW in the Carolinas and Florida at an investment of over $2 billion. As a result of the installation of environmental controls and the retirement of unscrubbed coal-fired plants, our emissions profile will be significantly reduced while strengthening our fuel diversification. We believe that these actions will help address growing environmental constraints on coal-fired generation and take advantage of favorable prices for U.S. natural gas as well as improvements in combined-cycle technology.

We are making a significant investment in smart grid technology with initiatives partially funded by $200 million of federal matching infrastructure funds. Reimbursements totaling $89 million have been received to date.

New nuclear generation is a vital long-term part of our balanced solution strategy. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building one or more plants. The Utilities have each filed a COL application with the NRC for two additional reactors each at Harris and at 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. During 2011, the NRC approved the reactor design selected for Levy and Harris, and a decision on the Levy COL is expected in 2013. Once we have received the COL, we will assess the project and determine the schedule. As discussed in "Matters Impacting Future Results and Liquidity," PEF's comprehensive settlement agreement addresses recovery of Levy costs through 2017.

We are preparing for an energy future that includes, among other things, carbon reductions and emerging technologies such as smart grid and plug-in electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework that will prepare us for this new energy future.

CONTINUOUS BUSINESS EXCELLENCE

For the past several years, we have been applying a continuous improvement framework to our operations through our Continuous Business Excellence initiative. Through a disciplined approach to identifying and eliminating waste and continuously improving our business, we are developing sustainable process improvements. In addition, we have been applying the "Lean" process to our operations (Lean is a set of principles, tools and techniques for improving the operating performance of any business). In addition to the improvement events held across our company during 2011, we are applying Lean principles to our merger integration activities discussed above.

MATTERS IMPACTING FUTURE RESULTS AND LIQUIDITY

Our future financial results and liquidity can be impacted by a number of factors, as more fully discussed in Item 1, "Business," and Item 1A, "Risk Factors." Declines in demand for electricity can result from economic downturns as well as unseasonable weather. The Utilities are subject to regulation on the federal and state level. Changes in laws and regulation 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, results of operations and cash flows, particularly if the costs of those changes are not fully recoverable from our ratepayers.

As more fully discussed in Note 8C, the FPSC has approved a comprehensive settlement agreement between PEF and consumer advocates in Florida that provides customers a refund of $288 million, removes CR3 from base rates while we continue to analyze options for the plant, limits the costs customers will be charged through 2017 for Levy and allows for base rates to adjust in 2013. The settlement agreement will take effect with the first billing cycle of January 2013. When all the agreement provisions are factored in, the estimated 2013 total increase for the average PEF residential bill is approximately $4.93 per 1,000 kilowatt-hours (kWh), or 4 percent, over current rates. The total PEF customer bill for 2013 and beyond will change as the cost-recovery clause components of the customer bills change. Those expenses are filed and reviewed with the FPSC each year, separate from the base rate.

Despite the recent court-ordered stay of a new air pollution regulation that was slated to go into effect in 2012, we continue to work to lessen the environmental impact of our power plants through our balanced solution strategy. We expect environmental regulations to continue to evolve, including those regarding water quality and the reduction of emissions from coal-fired plants. Compliance is anticipated to require significant capital expenditures that could impact our financial condition, results of operations and cash flows. However, we anticipate that such costs would be eligible for regulatory recovery through either base rates or cost-recovery clauses.

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.

We compute our non-GAAP financial measurement "Ongoing Earnings" as GAAP net income attributable to controlling interests less discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one

reporting period but are not considered representative of fundamental core earnings. 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. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies.

A reconciliation of Ongoing Earnings to GAAP net income attributable to controlling interests follows:

(in millions except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Year ended December 31, 2011					
Ongoing Earnings	**$ 541**	**$ 530**	**$ (200)**	**$ 871**	**$ 2.95**
Impairment, net of tax[a]	**(2)**	**-**	**-**	**(2)**	**(0.01)**
Plant retirement charge, net of tax[a]	**(1)**	**-**	**-**	**(1)**	**-**
CVO mark-to-market, net of tax[a]	**-**	**-**	**(45)**	**(45)**	**(0.16)**
Merger and integration costs, net of tax[a]	**(25)**	**(21)**	**-**	**(46)**	**(0.16)**
CR3 indemnification charge, net of tax[a]	**-**	**(20)**	**-**	**(20)**	**(0.06)**
Amount to be refunded to customers, net of tax[b]	**-**	**(177)**	**-**	**(177)**	**(0.60)**
Discontinued operations attributable to controlling interests, net of tax	**-**	**-**	**(5)**	**(5)**	**(0.02)**
Net income (loss) attributable to controlling interests[c]	**$ 513**	**$ 312**	**$ (250)**	**$ 575**	**$ 1.94**
Year ended December 31, 2010					
Ongoing Earnings	$ 618	$ 462	$ (191)	$ 889	$ 3.06
Impairment, net of tax[a]	(5)	(1)	-	(6)	(0.02)
Plant retirement charge, net of tax[a]	(1)	-	-	(1)	-
Change in the tax treatment of the Medicare Part D subsidy	(12)	(10)	-	(22)	(0.08)
Discontinued operations attributable to controlling interests, net of tax	-	-	(4)	(4)	(0.01)
Net income (loss) attributable to controlling interests[c]	$ 600	$ 451	$ (195)	$ 856	$ 2.95
Year ended December 31, 2009					
Ongoing Earnings	$ 540	$ 460	$ (154)	$ 846	$ 3.03
Impairment, net of tax[a]	-	-	(2)	(2)	(0.01)
Plant retirement charge, net of tax[a]	(17)	-	-	(17)	(0.06)
CVO mark-to-market	-	-	19	19	0.07
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[c]	$ 513	$ 460	$ (216)	$ 757	$ 2.71

[a] Calculated using assumed tax rate of 40 percent to the extent items are tax deductible.

[b] Calculated using PEF's statutory tax rate of 38.6 percent.

[c] 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 (See Note 20).

OVERVIEW

FOR 2011 AS COMPARED TO 2010 and 2010 AS COMPARED TO 2009

For the year ended December 31, 2011, our net income attributable to controlling interests was $575 million, or $1.94 per share, compared to net income attributable to controlling interests of $856 million, or $2.95 per share, for the same period in 2010. The decrease as compared to prior year was primarily due to:

- the charge recorded for the amount to be refunded to customers through the fuel clause in accordance with PEF's 2012 settlement agreement (Ongoing Earnings adjustment);
- less favorable impact of weather at the Utilities;
- loss recorded due to mark-to-market change in fair value of contingent value obligations (CVOs) (Ongoing Earnings adjustment) and
- lower wholesale base revenues at the Utilities.

Partially offsetting these items was:

- lower depreciation and amortization expense recoverable through base rates in accordance with PEF's 2010 settlement agreement.

For the year ended December 31, 2010, our net income attributable to controlling interests was $856 million, or $2.95 per share, compared to net income attributable to controlling interests of $757 million, or $2.71 per share, for the same period in 2009. The increase as compared to prior year was primarily due to:

- favorable weather at the Utilities and
- lower loss from discontinued non-utility businesses (Ongoing Earnings adjustment).

Partially offsetting these items was:

- higher O&M expenses at the Utilities.

PROGRESS ENERGY CAROLINAS

PEC contributed net income available to parent totaling $513 million, $600 million and $513 million in 2011, 2010 and 2009, respectively. The decrease in net income available to parent for 2011 as compared to 2010 was primarily due to the less favorable impact of weather and merger and integration costs. The increase in net income available to parent for 2010 as compared to 2009 was primarily due to the favorable impact of weather, favorable allowance for funds used during construction (AFUDC) equity and favorable retail customer growth and usage, partially offset by higher O&M expenses.

PEC contributed Ongoing Earnings of $541 million, $618 million and $540 million for 2011, 2010 and 2009, respectively. The 2011 Ongoing Earnings adjustments to net income available to parent were a $25 million charge, net of tax, for merger and integration costs, a $2 million impairment of certain miscellaneous investments, net of tax, and a $1 million plant retirement charge, net of tax, related to PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives. The 2010 Ongoing Earnings adjustments to net income available to parent were a $12 million charge for the change in the tax treatment of the Medicare Part D subsidy, a $5 million impairment of certain miscellaneous investments and other assets, net of tax, and a $1 million plant retirement charge, net of tax. The 2009 Ongoing Earnings adjustments to net income available to parent were a $17 million plant retirement charge, net of tax, 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 items to be representative of PEC's fundamental core earnings and excluded these items in computing PEC's Ongoing Earnings.

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, fuel and other pass-through revenues and refunds, if any. 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. PEC's clause-recoverable regulatory returns include renewable energy clause revenues and the return on asset component of DSM and EE. The reconciliation and analysis that follows is a complement to the financial information provided in accordance with GAAP.

A reconciliation of PEC's Base Revenues to GAAP operating revenues, including the percentage change by customer class and by year, follows:

(in millions) Customer Class	2011	% Change	2010	% Change	2009
Residential	$ 1,185	(4.6)	$ 1,242	10.1	$ 1,128
Commercial	712	(1.9)	726	2.7	707
Industrial	365	-	365	2.5	356
Governmental	65	-	65	10.2	59
Unbilled	(34)	NM	10	NM	5
Total retail base revenues	2,293	(4.8)	2,408	6.8	2,255
Wholesale base revenues	285	(6.6)	305	(1.0)	308
Total Base Revenues	2,578	(5.0)	2,713	5.9	2,563
Clause-recoverable regulatory returns	31	138.5	13	44.4	9
Miscellaneous	129	(6.5)	138	21.1	114
Fuel and other pass-through revenues	1,790	NM	2,058	NM	1,941
Total operating revenues	$ 4,528	(8.0)	$ 4,922	6.4	$ 4,627

NM - not meaningful

PEC's total Base Revenues were $2.578 billion and $2.713 billion for 2011 and 2010, respectively. The $135 million decrease in Base Revenues was due primarily to the $107 million unfavorable impact of weather and $20 million lower wholesale base revenues. The unfavorable impact of weather was driven by 20 percent lower heating-degree days and 5 percent lower cooling-degree days than 2010. Cooling-degree days were 19 percent higher than normal and heating-degree days were 9 percent lower than normal in 2011. See "Seasonality and the Impact of Weather" in Item 1, "Business," for a summary of degree days and weather estimation. The lower wholesale base revenues was primarily due to the $15 million impact of lower demand driven by the unfavorable impact of weather and the $7 million impact of a contract that expired in early 2011.

PEC's clause-recoverable regulatory returns increased $18 million in 2011 primarily due to recovery of increased spending on DSM programs.

PEC's total Base Revenues were $2.713 billion and $2.563 billion for 2010 and 2009, respectively. The $150 million increase in Base Revenues was due primarily to the $115 million favorable impact of weather and the $36 million favorable impact of retail customer growth and usage. The favorable impact of weather was driven by 15 percent higher heating-degree days and 24 percent higher cooling-degree days than 2009. Additionally, cooling degree-days were 30 percent higher and heating degree-days were 14 percent higher than normal. The favorable impact of retail customer growth and usage was driven by an increase in the average usage per retail customer and a net 10,000 increase in the average number of customers for 2010 compared to 2009.

PEC's miscellaneous revenues increased $24 million in 2010, which includes $10 million higher transmission revenues driven by higher rates resulting from transmission asset additions.

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

(in millions of kWh) Customer Class	**2011**	% Change	2010	% Change	2009
Residential	**18,148**	(5.0)	19,108	11.6	17,117
Commercial	**13,844**	(2.4)	14,184	4.0	13,639
Industrial	**10,613**	(0.5)	10,665	2.9	10,368
Governmental	**1,610**	2.3	1,574	5.1	1,497
Unbilled	**(597)**	NM	172	NM	360
Total retail kWh sales	**43,618**	(4.6)	45,703	6.3	42,981
Wholesale	**12,605**	(10.0)	13,999	0.2	13,966
Total kWh sales	**56,223**	(5.8)	59,702	4.8	56,947

The decrease in retail kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed.

The decrease in wholesale kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed, and a contract that expired in early 2011.

The increase in retail kWh sales in 2010 was primarily due to favorable weather, as previously discussed.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation and 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 and is recorded as deferred fuel expense, which is included in fuel used in electric generation on the Consolidated Statements of Income.

Fuel and purchased power expenses were $1.702 billion for 2011, which represents a $286 million decrease compared to 2010. This decrease was primarily due to the $169 million impact of lower fuel rates and the $112 million impact of lower system requirements resulting from the unfavorable impact of weather compared to 2010. See "Electric Utility Regulated Operating Statistics – PEC" in Item 1, "Business," for a summary of average fuel costs.

Fuel and purchased power expenses were $1.988 billion for 2010, which represents a $79 million increase compared to 2009. This increase was primarily due to the $324 million impact of higher system requirements resulting from favorable weather and the impact of nuclear plant outages on PEC's generation mix, partially offset by $151 million decreased fuel costs in 2010 driven by lower coal and gas prices and $104 million lower deferred fuel expense. The decrease in deferred fuel expense was primarily due to higher fuel and purchased power expenses and lower fuel rates in North Carolina.

Operation and Maintenance

O&M expense was $1.182 billion for 2011, which represents a $24 million increase compared to 2010. This increase was primarily due to $48 million higher nuclear plant O&M costs, $41 million of merger and integration costs, $23 million higher storm costs, $12 million higher fossil generation outage and maintenance costs, $7 million higher vegetation management expense, and a $6 million prior-year nuclear insurance refund, partially offset by $91 million lower nuclear plant outage costs, the $27 million noncapital portion of a judgment from spent fuel litigation (See Note 22D) and the $2 million prior-year impairment of other assets. The higher nuclear plant O&M costs are

primarily due to increased spending to improve the performance of Robinson and higher spent fuel storage costs in 2011 as compared to 2010. The lower nuclear plant outage costs are primarily due to two nuclear refueling and maintenance outages in 2011 compared to three in 2010. There were $2 million and $1 million of coal plant retirement charges recognized in 2011 and 2010, respectively. Management does not consider merger and integration costs, impairments and charges recognized for the retirement of generating units prior to the end of their estimated useful lives to be representative of PEC's fundamental core earnings. Therefore, the impacts of these items are excluded in computing PEC's Ongoing Earnings. Certain O&M expenses such as the cost of reagents for emission control equipment and wheeling charges are recoverable through cost-recovery clauses. In aggregate, O&M expenses primarily recoverable through base rates increased $15 million compared to the same period in 2010.

O&M expense was $1.158 billion for 2010, which represents an $86 million increase compared to 2009. This increase was primarily due to $78 million higher nuclear plant outage and maintenance costs, $11 million higher employee benefits expense driven by revised actuarial estimates, $7 million higher emission expense primarily due to sales of NOx emission allowances in the prior year and the $2 million impairment of other assets, partially offset by $27 million lower coal plant retirement charges. The higher nuclear plant outage and maintenance costs are primarily due to three nuclear refueling and maintenance outages in 2010 compared to two in 2009 as well as extended outages and more emergent work in 2010 as compared to 2009. As previously discussed, management does not consider impairments and charges recognized for the retirement of generating units prior to the end of their estimated useful lives to be representative of PEC's fundamental core earnings. Therefore, the impacts of these items are excluded in computing PEC's Ongoing Earnings. Also, as previously discussed, certain O&M expenses are recoverable through cost-recovery clauses. In aggregate, O&M expenses primarily recoverable through base rates increased $69 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $514 million, $479 million and $470 million for 2011, 2010 and 2009, respectively. The $35 million increase in 2011 was primarily due to higher depreciable asset base driven by placing the newly constructed combined-cycle unit at the Smith Energy Complex into service in mid-2011.

Other

Other operating expense was $34 million for 2011, which represents a $26 million increase compared to 2010. The $34 million expense in 2011 was primarily due to the $28 million retail disallowance of replacement power costs resulting from the prior-year performance of nuclear plants (See Note 8B). The $8 million expense in 2010 was primarily due to the $7 million impairment of certain miscellaneous investments. Management does not consider impairments to be representative of PEC's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEC's Ongoing Earnings.

Total Other Income, Net

Total other income, net was $71 million for 2011, which represents a $4 million increase compared to 2010. This increase was primarily due to favorable AFUDC equity of $7 million resulting from increased construction project costs, partially offset by $4 million impairment of certain miscellaneous investments. Management does not consider impairments to be representative of PEC's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEC's Ongoing Earnings.

Total other income, net was $67 million for 2010, which represents a $47 million increase compared to 2009. This increase was primarily due to favorable AFUDC equity of $31 million resulting from increased construction project costs and a $16 million cumulative prior period adjustment charge recorded in 2009 related to certain employee life insurance benefits. The prior period adjustment was not material to 2009 or previously issued financial statements. Management determined that the adjustment should be excluded in computing PEC's Ongoing Earnings.

Income Tax Expense

Income tax expense was $256 million, $350 million and $277 million in 2011, 2010 and 2009, respectively. The $94 million decrease in 2011 compared to 2010 was primarily due to the $72 million impact of lower pre-tax income and

the $12 million prior-year impact of the change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted in 2010 (See Note 17). The $73 million income tax expense increase in 2010 compared to 2009 was primarily due to the $64 million impact of higher pre-tax income and the $12 million impact of the Medicare Part D subsidy previously discussed. Management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEC's fundamental core earnings and, therefore, the amount is excluded in computing PEC's Ongoing Earnings.

PROGRESS ENERGY FLORIDA

PEF contributed net income available to parent totaling $312 million, $451 million and $460 million in 2011, 2010 and 2009, respectively. The decrease in net income available to parent for 2011 as compared to 2010 was primarily due to the charge for the amount to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement and the less favorable impact of weather, partially offset by lower depreciation and amortization expense recoverable through base rates. The decrease in net income available to parent for 2010 compared to 2009 was primarily due to unfavorable AFUDC equity and higher O&M expenses, partially offset by the favorable impact of weather and higher clause-recoverable regulatory returns.

PEF contributed Ongoing Earnings of $530 million, $462 million and $460 million in 2011, 2010 and 2009, respectively. The 2011 Ongoing Earnings adjustments to net income available to parent were a $177 million charge, net of tax, for the amount to be refunded to customers through the fuel clause, a $21 million charge, net of tax, for merger and integration costs and a $20 million charge, net of tax, for indemnification for the estimated future years' joint owner replacement power costs for CR3. The 2010 Ongoing Earnings adjustments to net income available to parent were a $10 million charge for the change in the tax treatment of the Medicare part D subsidy and a $1 million impairment of other assets, net of tax. Management does not consider these charges to be representative of PEF's fundamental core earnings and excluded these charges in computing PEF's Ongoing Earnings. There were no Ongoing Earnings adjustments in 2009.

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, fuel and other pass-through revenues and refunds, if any. 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. PEF's clause-recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and environmental cost recovery clause (ECRC) revenues. The reconciliation and analysis that follows is a complement to the financial information we provide in accordance with GAAP.

A reconciliation of PEF's Base Revenues to GAAP operating revenues, including the percentage change by customer class and by year, follows:

(in millions) Customer Class	2011	% Change	2010	% Change	2009
Residential	$ **983**	(5.9)	$ 1,045	10.5	$ 946
Commercial	**356**	(0.8)	359	5.6	340
Industrial	**74**	(1.3)	75	4.2	72
Governmental	**90**	(2.2)	92	5.7	87
Unbilled	**(24)**	NM	17	NM	9
Total retail base revenues	**1,479**	(6.9)	1,588	9.2	1,454
Wholesale base revenues	**110**	(31.3)	160	(22.7)	207
Total Base Revenues	**1,589**	(9.1)	1,748	5.2	1,661
Clause-recoverable regulatory returns	**182**	5.2	173	98.9	87
Miscellaneous	**209**	(3.2)	216	14.3	189
Amount to be refunded to customers	**(288)**	NM	-	-	-
Fuel and other pass-through revenues	**2,677**	NM	3,117	NM	3,314
Total operating revenues	$ **4,369**	(16.8)	$ 5,254	0.1	$ 5,251

PEF's total Base Revenues were $1.589 billion and $1.748 billion for 2011 and 2010, respectively. The $159 million decrease in Base Revenues was due primarily to the $112 million unfavorable impact of weather and $50 million lower wholesale base revenues. The unfavorable impact of weather was driven by 61 percent lower heating-degree days than 2010. Additionally, heating-degree days were 12 percent lower than normal. See "Seasonality and the Impact of Weather" in Item 1, "Business," for a summary of degree days and weather estimation. The lower wholesale base revenues were primarily due to decreased revenues from contracts that expired in 2010.

PEF's amount to be refunded to customers of $288 million in 2011 represents the refund to customers through the fuel clause in accordance with the 2012 settlement agreement (See Note 8C). PEF will refund $129 million in each of 2013 and 2014, and an additional $10 million annually to residential and small commercial customers in 2014, 2015 and 2016. Management does not consider the amount to be refunded to customers to be representative of PEF's fundamental core earnings. Therefore, the impact of this item is excluded in computing PEF's Ongoing Earnings.

PEF's total Base Revenues were $1.748 billion and $1.661 billion for 2010 and 2009, respectively. The $87 million increase in Base Revenues was due primarily to the $88 million favorable impact of weather and the $50 million impact of increased retail base rates associated with the repowered Bartow Plant, partially offset by $47 million lower wholesale base revenues and the $5 million unfavorable impact of net retail customer growth and usage. The favorable impact of weather was driven by 89 percent higher heating-degree days than 2009. Additionally, heating-degree days were 124 percent higher than normal. The lower wholesale base revenues were primarily due to an amended contract with a major customer. 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 4,000 increase in the average number of customers for 2010 compared to 2009.

PEF's clause-recoverable regulatory returns increased $86 million in 2010 primarily due to higher returns on ECRC assets due to placing approximately $1 billion of CAIR projects into service in late 2009 and mid-2010.

PEF's miscellaneous revenues increased $27 million in 2010 primarily due to $20 million higher transmission revenues driven by favorable weather and $8 million higher right-of-use revenues related to the use of easements and land.

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

(in millions of kWh) Customer Class	**2011**	% Change	2010	% Change	2009
Residential	**19,238**	(6.3)	20,524	5.8	19,399
Commercial	**11,892**	-	11,896	0.1	11,884
Industrial	**3,243**	0.7	3,219	(2.0)	3,285
Governmental	**3,224**	(1.9)	3,286	0.9	3,256
Unbilled	**(629)**	NM	458	NM	131
Total retail kWh sales	**36,968**	(6.1)	39,383	3.8	37,955
Wholesale	**2,610**	(32.3)	3,857	0.6	3,835
Total kWh sales	**39,578**	(8.5)	43,240	3.5	41,790

The decrease in retail kWh sales in 2011 was primarily due to unfavorable impact of weather, as previously discussed.

Wholesale kWh sales decreased in 2011 primarily due to decreased sales from contracts that expired in 2010.

The increase in retail kWh sales in 2010 was primarily due to the favorable impact of weather as previously discussed.

Wholesale kWh sales increased in 2010 primarily due to the favorable impact of weather, which resulted in increased deliveries under a certain capacity contract that has high demand and low energy charges. Despite the increase in sales, wholesale base revenues decreased primarily due to a contract amendment as previously discussed.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation and 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 and is recorded as deferred fuel expense, which is included in fuel used in electric generation on the Consolidated Statements of Income.

Fuel and purchased power expenses totaled $2.284 billion in 2011, which represents a $307 million decrease compared to 2010. This decrease was primarily due to lower current year fuel and purchased power costs of $366 million and a decrease in the recovery of deferred capacity costs of $158 million, partially offset by an increase in deferred fuel expense of $217 million. The lower fuel and purchased power costs were driven by the $385 million impact of lower system requirements in 2011 as a result of the unfavorable impact of weather as previously discussed and lower natural gas prices in 2011, partially offset by the $32 million CR3 indemnification charge for the estimated joint owner replacement power costs for future years (through the expiration of the indemnification provisions of the joint owner agreement) that was recorded in 2011 (See Note 8C for a discussion of the CR3 outage and Note 22C for a discussion of the related indemnification). The decrease in the recovery of deferred capacity costs was due to decreased current year rates. Deferred fuel expense increased due to the higher under-recovered fuel costs in 2010 as a result of higher system requirements due to extreme weather. See "Electric Utility Regulated Statistics - PEF" in Item 1, "Business," for a summary of average fuel costs. Management does not consider the CR3 indemnification of future years' joint owner replacement power costs to be representative of PEF's fundamental core earnings. Therefore, the impact of this item is excluded in computing PEF's Ongoing Earnings.

Fuel and purchased power expenses totaled $2.591 billion in 2010, which represents a $163 million decrease compared to 2009. This decrease was primarily due to lower deferred fuel expense of $520 million resulting from lower fuel rates, which assumed the CR3 outage was completed in 2009, partially offset by increased fuel and purchased power costs in 2010 of $189 million and an increase in the recovery of deferred capacity costs of $167 million. The increased fuel and purchased power costs were primarily driven by higher system requirements

resulting from the favorable impact of weather and CR3 replacement power costs net of insurance recovery. The increase in the recovery of deferred capacity costs was primarily due to increased rates and higher system requirements due to favorable weather.

Operation and Maintenance

O&M expense was $881 million in 2011, which represents a $31 million decrease compared to 2010. This decrease was primarily due to $19 million lower ECRC costs resulting from a refund of the 2010 over-recovery, $14 million lower employee-related expenses, $11 million lower vegetation management expense, $7 million lower uncollectible account expense, $5 million lower environmental remediation expense and $2 million prior-year impairment of other assets, partially offset by $35 million of merger and integration costs. Management does not consider impairments and merger and integration costs to be representative of PEF's fundamental core earnings. Therefore, the impact of these items is excluded in computing PEF's Ongoing Earnings. The ECRC costs and certain other O&M expenses are recoverable through cost-recovery clauses and, therefore, have no material impact on earnings. In aggregate, O&M expenses primarily recoverable through base rates decreased $15 million compared to the same period in 2010.

O&M expense was $912 million in 2010, which represents a $73 million increase compared to 2009. This increase was primarily due to the $34 million prior-year pension deferral in accordance with an FPSC order; $22 million higher employee benefits expense driven by revised actuarial estimates; $18 million higher Energy Conservation Cost Recovery Clause (ECCR) costs driven by higher deferred expenses due to higher rates, increased energy sales and increased customer usage of load management programs and home improvement incentives; the $11 million prior-year impact of a change in vacation benefits policy; and the $2 million impairment of other assets. These increases are partially offset by $22 million favorable ECRC costs due to lower NOx allowances used resulting from a scrubber placed in service in December 2009. The ECCR and ECRC expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Management does not consider impairments to be representative of PEF's fundamental core earnings. Therefore, the impacts of impairments are excluded in computing PEF's Ongoing Earnings. In aggregate, O&M expenses primarily recoverable through base rates increased $80 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $169 million for 2011, which represents a $257 million decrease compared to 2010. This decrease was primarily due to the $190 million increase in the reduction of the cost of removal component of amortization expense in accordance with the 2010 settlement agreement (See Note 8C) and $45 million lower nuclear cost-recovery amortization. The decrease in the nuclear cost-recovery amortization is due to lower approved recovery of preconstruction and carrying costs resulting from schedule shifts in the Levy project (See Note 8C). The nuclear cost-recovery amortization is recovered through a cost-recovery clause and, therefore, has no material impact on earnings. In aggregate, depreciation, amortization and accretion expenses recoverable through base rates or the ECRC decreased $178 million compared to the same period in 2010. In accordance with PEF's 2010 and 2012 settlement agreements, PEF will have the discretion to reduce the cost of removal component of amortization expense in 2012 and beyond, as well, subject to limitations (See Note 8C).

Depreciation, amortization and accretion expense was $426 million for 2010, which represents a $76 million decrease compared to 2009. This decrease was primarily due to a reduction in the cost of removal component of amortization expense of $60 million in accordance with the 2010 settlement agreement, the lower depreciation rate impact of $43 million and other adjustments required in the 2010 settlement agreement of $13 million, partially offset by the $46 million impact of depreciable asset base increases. The lower depreciation rate resulted from a depreciation study in conjunction with the 2009 base rate case.

Taxes Other Than on Income

Taxes other than on income was $350 million for 2011, which represents a $12 million decrease compared to 2010. This decrease was primarily due to lower gross receipts and franchise taxes of $21 million resulting from lower operating revenues, partially offset by higher property taxes of $12 million resulting primarily from an increase in taxable plant basis. Taxes other than on income was $362 million for 2010, which represents an increase of $15

million compared to 2009, primarily due to higher property taxes of $14 million resulting primarily from placing the repowered Bartow Plant in service in mid-2009. 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 income of $13 million in 2011 and expense of $4 million and $7 million in 2010 and 2009, respectively. The $13 million income in 2011 was primarily due to a favorable litigation judgment. The $7 million expense in 2009 was primarily due to regulatory disallowance of fuel costs.

Total Other Income, Net

Total other income, net was $35 million for 2011, which represents a $7 million increase compared to 2010. This increase was primarily due to $4 million favorable AFUDC equity related to higher eligible construction project costs.

Total other income, net was $28 million for 2010, which represents a $72 million decrease compared to 2009. This decrease was primarily due to $63 million unfavorable AFUDC equity related to lower eligible construction project costs, primarily due to placing the repowered Bartow Plant and CAIR projects into service in mid- and late 2009, respectively.

Total Interest Charges, Net

Total interest charges, net was $239 million for 2011, which represents a $19 million decrease compared to 2010. This decrease was primarily due to the 2011 settlement of 2004 and 2005 income tax audits.

Total interest charges, net was $258 million in 2010, which represents a $27 million increase compared to 2009. This increase was primarily due to $16 million higher interest driven by higher average long-term debt outstanding and $14 million unfavorable AFUDC debt related to costs associated with eligible construction projects as discussed above.

Income Tax Expense

Income tax expense was $180 million, $276 million and $209 million in 2011, 2010 and 2009, respectively. The $96 million decrease in 2011 compared to 2010 was primarily due to the $91 million impact of lower pre-tax income and the $10 million prior-year impact of the change in the tax treatment of the Medicare Part D subsidy resulting from federal health care reform enacted in 2010 (See Note 17). The $67 million income tax expense increase in 2010 compared to 2009 was primarily due to the $24 million impact of the unfavorable AFUDC equity discussed above, the $23 million impact of higher pre-tax income and the $10 million impact of the Medicare Part D subsidy previously discussed. AFUDC equity is excluded from the calculation of income tax expense. Management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEF's fundamental core earnings. Accordingly, the impact of the change is excluded in computing PEF's Ongoing Earnings.

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 that follows. 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)	2011	Change	2010	Change	2009
Other interest expense	$ (302)	$ (4)	$ (298)	$ (52)	$ (246)
Other income tax benefit	117	1	116	19	97
Other expense	(15)	(6)	(9)	(4)	(5)
Ongoing Earnings	(200)	(9)	(191)	(37)	(154)
CVO mark-to-market, net of tax	(45)	(45)	-	(19)	19
Impairment, net of tax	-	-	-	2	(2)
Discontinued operations attributable to controlling interests, net of tax	(5)	(1)	(4)	75	(79)
Net loss attributable to controlling interests	$ (250)	$ (55)	$ (195)	21	$ (216)

OTHER INTEREST EXPENSE

Other interest expense was $302 million, $298 million and $246 million for 2011, 2010 and 2009, respectively. The $52 million increase for 2010 compared to 2009 was primarily due to higher average debt outstanding at the Parent.

OTHER INCOME TAX BENEFIT

Other income tax benefit was $117 million, $116 million and $97 million for 2011, 2010 and 2009, respectively. The $19 million increase for 2010 compared to 2009 was primarily due to the favorable tax impact of higher pre-tax loss.

OTHER EXPENSE

Other expense was $15 million, $9 million and $5 million for 2011, 2010 and 2009, respectively. The $6 million increase in 2011 was primarily due to higher stock-based compensation expense resulting from the increase in Progress Energy's stock price.

ONGOING EARNINGS ADJUSTMENTS

CVO Mark-to-Market

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress in 2000. Each CVO represents the right of the holder to receive contingency 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 16). As a result of a settlement agreement with a CVO holder and a tender offer to CVO holders at a purchase price of $0.75 per CVO (See Note 16), Progress Energy repurchased 80.1 million CVOs in 2011. Progress Energy recorded a pre-tax loss of $59 million in 2011 and a gain of $19 million in 2009 to record the change in fair value of the CVOs, which had average unit prices of $0.75 at December 31, 2011 and $0.16 at December 31, 2010 and 2009. The 18.5 million outstanding CVOs not held by Progress Energy at December 31, 2011, had a fair value of $14 million. The 98.6 million CVOs outstanding at December 31, 2010 and 2009 had a fair value of $15 million. The gain/loss recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income. Because Progress Energy is unable to predict the changes in the fair value of the CVOs, management does not consider this adjustment to be representative of our fundamental core earnings. Therefore, the impact of changes in the fair value of CVOs is excluded in computing our Ongoing Earnings.

Impairment, Net of Tax

We recorded a $3 million impairment of investments in 2009. The impairment was recorded in other, net on the Consolidated Statements of Income. Management does not consider impairments to be representative of our fundamental core earnings. Therefore, the impacts of impairments are excluded in computing our Ongoing Earnings.

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 4 for additional information related to discontinued operations. We recognized $5 million, $4 million and $79 million of losses from discontinued operations attributable to controlling interests, net of tax, for 2011, 2010 and 2009, respectively. Management does not consider operating results of discontinued operations to be representative of our fundamental core earnings. Therefore, the impacts of operating results of discontinued operations are excluded in computing our Ongoing Earnings.

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 (See Note 22D). As a result, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability.

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 rates (prices) 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 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, results of operations and cash flows may be materially impacted. See Note 8 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)	2011	2010
Progress Energy	$ 22,497	$ 21,240
PEC	11,887	10,961
PEF	10,523	10,189

As discussed in Note 14, 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 in order to reflect the ratemaking treatment of the related costs.

Progress Energy's, PEC's and PEF's total AROs at December 31, 2011, were $1.265 billion, $896 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 90 percent, respectively, of Progress Energy's, PEC's and PEF's total AROs at December 31, 2011. 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, which PEC filed with the NCUC in 2010. 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, which was updated with the most currently available escalation rates in 2010 (See Note 5C). 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 $21 million.

GOODWILL

As discussed in Note 9, 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 reporting units and our goodwill impairment tests are performed at the utility reporting unit level. The carrying amounts of goodwill at December 31, 2011 and 2010, for the PEC and PEF reporting units were $1.922 billion and $1.733 billion, respectively.

We calculate the fair value of our utility reporting units by considering various factors, including valuation studies based primarily on income and market approaches. Generally, more emphasis is applied to the income approach as substantially all of the Utilities' 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 Utilities 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 reporting units. The estimated future cash flows from operations are based on the Utilities' 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 reporting units 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 reporting unit 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 reporting units. 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 reporting units could be significantly different in future periods, which could result in a future impairment charge to goodwill.

Our 2011 annual test relied primarily on a market approach, which was based on the allocation of the fair value of the consideration to be received in the pending Merger to the utility reporting units. In addition, in response to uncertainty regarding CR3, management performed an additional analysis for the PEF reporting unit based primarily on income and market approaches as previously described. The results of our 2011 annual test of goodwill indicated that the fair values of the PEC and PEF reporting units substantially exceeded their respective carrying values, and therefore the carrying amounts of goodwill for the PEC and PEF reporting units were not impaired.

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 reporting unit below its carrying value.

UNBILLED REVENUE

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utilities base revenues, primarily related to retail 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 throughout 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 retail 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)	2011	2010
Progress Energy	$ 157	$ 223
PEC	102	136
PEF	55	87

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 15, 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 are 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 17A, 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.

We have pension plan assets with a fair value of approximately $2.2 billion at December 31, 2011. For 2011, our expected rate of return on pension plan assets was 8.50%. 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 2011, we lowered the expected rate of return from the previously used 8.75%, due primarily to a shift in our investment strategy. A 25 basis point change in the expected rate of return for 2011 would have changed 2011 pension costs by approximately $5 million. For 2012, we have assumed an expected rate of return of 8.25%, which is reflected in the estimates of total 2012 pension costs discussed within this section.

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 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.

Due to a 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 4.75% at December 31, 2011, from 5.65% at December 31, 2010, which will increase 2012 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 experienced returns of approximately 5% in 2011. That negative asset performance, as compared to our expected asset returns, will result in increased pension costs in 2012, all other factors remaining constant. In addition, contributions to pension plan assets in 2011 and in 2012 will result in decreased pension costs in 2012 due to increased asset balances and resulting expected earnings on those assets, all other factors remaining constant.

Evaluations of our 2012 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2012 will be $110 million to $120 million, compared with $88 million recognized in 2011. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

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 2012 pension costs. PEC estimates that the total cost recognized for pensions in 2012 will be $30 million to $35 million, compared with $24 million recognized in 2011. A 25 basis point change in the expected rate of return for 2011 would have changed PEC's 2011 pension costs by approximately $3 million. PEF estimates that the total cost recognized for pensions in 2012 will be $50 million to $55 million, compared with $39 million recognized in 2011. A 25 basis point change in the expected rate of return for 2011 would have changed PEF's 2011 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 typically rely upon our operating cash flow, substantially all of which is generated by the Utilities, commercial paper and credit 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 will 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 and plant performance can lead to over- or under-recovery of fuel costs, as changes in fuel expense are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility and plant performance 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 and/or how our plants are performing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows, but not materially affect net income. In addition, as discussed in "Future Liquidity and Capital Resources" below, the amount and timing of applicable CR3 repair and associated replacement power recovery from NEIL could impact borrowing needs.

As a registered holding company, our establishment of intercompany extensions of credit is subject to regulation by the 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 $4.0 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 credit facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. During 2011, PEC paid dividends of $585 million and PEF paid dividends of $510 million to the Parent. PEC and PEF expect to pay dividends to the Parent in 2012. 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 issuances, borrowings under our credit facilities and/or long-term debt financings are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2012. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through the IPP and/or employee benefit and stock option plans to support our liquidity requirements (See "Financing Activities").

We have 23 financial institutions that support our combined $1.978 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, 2011, the Parent had no outstanding borrowings under its credit facility, $250 million of outstanding commercial paper and had issued $2 million of letters of credit supported by the revolving credit facility. At December 31, 2011, PEC and PEF had no outstanding borrowings under their respective credit facilities and $184 million and $233 million of outstanding commercial paper, respectively. Based on these outstanding amounts at December 31, 2011, there was a combined $1.309 billion available for additional borrowings.

At December 31, 2011, 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, 2011, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 18A for additional information with regard to our commodity derivatives.

At December 31, 2011, 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 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, 2011, the sums of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps were each in a net mark-to-market liability position. See Note 18B for additional information with regard to our interest rate derivatives.

The Wall Street Reform and Consumer Protection Act (H.R. 4173) includes, among other things, provisions related to the swaps and over-the-counter derivatives markets. Regulations related to these provisions to address items such as mandatory clearing and trading, reporting and capital and margin requirements have not yet been finalized. Given that we use commodity and interest rate hedges to mitigate commercial risk, we expect that we will be considered end users of these products under the law. Therefore, we expect that we will be exempt from the law's mandatory clearing and trading provisions, subject to certain reporting requirements. Capital and margin requirements for our

interest rate and commodity hedges, as well as the law's impact on our counterparties and other market participants, are expected to be determined as more detailed rules and regulations are published. At this time, we do not expect the law to have a material impact on our financial condition, results of operations and cash flows. However, we cannot determine the impact until the final regulations are issued.

Our pension 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. We will continue to monitor the credit markets to maintain an appropriate level of liquidity. Our ability to access the capital markets on favorable terms may be negatively impacted by credit rating actions. Risk factors associated with the capital markets 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 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

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, 2011, 2010 and 2009. Net cash provided by operating activities for the three years ended December 31, 2011, 2010 and 2009, was $1.615 billion, $2.537 billion and $2.271 billion, respectively.

Net cash provided by operating activities for 2011 decreased when compared to 2010. The $922 million decrease in operating cash flow was primarily due to $308 million higher cash used for inventory, the $219 million less favorable impact of weather as previously discussed, a $205 million increase in pension plan funding, $86 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011 and $72 million decrease in NEIL reimbursements for replacement power costs due to the CR3 extended outage (See "Future Liquidity and Capital Resources – Regulatory Matters and Recovery of Costs – CR3 Outage"). The increase in cash used for inventory was primarily due to the higher coal purchases in 2011 reflecting anticipated winter consumption and inventory levels that remained high at year-end (due to lower natural gas prices), combined with higher 2010 consumption of existing inventory levels to meet system requirements resulting from favorable weather.

Net cash provided by operating activities increased $266 million for 2010, when compared to 2009. The increase was primarily due to the $203 million favorable impact of weather, partially offset by $78 million higher nuclear plant outage and maintenance costs included in O&M, both as previously discussed; $197 million lower cash used for inventory, primarily due to higher coal consumption in 2010 as a result of favorable weather that was fulfilled through the 2010 usage of inventory from year-end 2009; $154 million payment in 2009 due to 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 (See Note 22D); $56 million net cash receipts for income taxes in 2010 compared to $87 million net cash payments for income taxes in 2009; and $121 million lower cash used for pension and other benefits, primarily due to a reduction of contributions made in 2010. These amounts were partially offset by a $2 million under-recovery of fuel in 2010 compared to a $290 million over-recovery of fuel in 2009 due to higher fuel costs and lower fuel rates in 2010 and $23 million of net payments of cash collateral to counterparties on derivative contracts in 2010 compared to $200 million net refunds of cash collateral in 2009.

The Utilities file annual requests with their respective state commissions seeking rate increases or decreases for fuel cost under- or over-recovery.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2011, 2010 and 2009, was $2.212 billion, $2.400 billion and $2.532 billion, respectively.

Net cash used by investing activities decreased by $188 million for 2011, when compared to 2010. This decrease was primarily due to a $155 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects at PEF, the $42 million of smart grid grant reimbursements and $27 million of litigation judgment proceeds, partially offset by $24 million increase in restricted cash used to support letters of credit.

Net cash used by investing activities decreased by $132 million for 2010, when compared to 2009. This decrease was primarily due to a $74 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects at PEF, partially offset by PEC's increased capital expenditures at the Wayne County, New Hanover County and Harris generating facilities, and a $64 million increase in receipt of NEIL insurance proceeds for repairs due to the CR3 extended outage.

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2011, 2010 and 2009, was $216 million, $(251) million and $806 million, respectively. See Note 11 for details of debt and credit facilities.

Net cash provided by financing activities increased by $467 million for 2011, when compared to 2010. The increase is primarily due to a $902 million increase in proceeds from short-term and long-term debt, net of retirements, partially offset by $381 million net decrease in issuances of common stock, primarily related to the Parent's 2010 common stock sales under the IPP.

Net cash used by financing activities increased by $1.057 billion for 2010, when compared to 2009. The increase was primarily due to an $817 million decrease in proceeds from short-term and long-term debt, net of retirements, and a $192 million decrease in issuances of common stock, primarily related to a 2009 public offering.

Our financing activities are described below.

2012

- On February 15, 2012, the Parent's $478 million revolving credit agreement (RCA) was amended to extend the expiration date from May 3, 2012, to May 3, 2013, with its existing syndicate of 14 financial institutions. The Parent originally entered into the five-year RCA on May 3, 2006. On May 2, 2008, the expiration date of the RCA was extended to May 3, 2012. The Parent ratably reduced the size of the RCA from $1.130 billion to $500 million on October 15, 2010, and the RCA was further reduced to $478 million on May 3, 2011, following the expiration of one financial institution's credit commitment of $22 million (See "Credit Facilities and Registration Statements").

2011

- On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due January 15, 2021. The net proceeds of $495 million, along with available cash on hand, were used to retire the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011.

- On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt borrowings.

- On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

- On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

- Progress Energy issued approximately 2.0 million shares of common stock resulting in approximately $53 million in proceeds from the IPP and its employee benefit and equity incentive plans. Included in these amounts

were approximately 2.0 million shares for proceeds of approximately $52 million issued under equity incentive plans. For 2011, the dividends paid on common stock were approximately $734 million.

2010

- On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with a portion of the proceeds from the $950 million of Senior Notes issued in November 2009.

- On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due 2020 and $350 million of 5.65% First Mortgage Bonds due 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

- On October 15, 2010, PEC and PEF each entered into new $750 million, three-year RCAs with a syndication of 22 financial institutions. The RCAs are used to provide liquidity support for PEC's and PEF's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCAs will expire on October 15, 2013. The new $750 million RCAs replaced PEC's and PEF's $450 million RCAs, which were set to expire June 28, 2011, and March 28, 2011, respectively. Both $450 million RCAs were terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").

- Progress Energy issued approximately 12.2 million shares of common stock resulting in approximately $434 million in proceeds from the IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 11.2 million shares for proceeds of approximately $431 million issued for the IPP. For 2010, the dividends paid on common stock were approximately $718 million.

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 IPP and certain employee benefit plans. For 2009, the dividends paid on common stock were approximately $693 million.

SHORT-TERM DEBT

At December 31, 2011, Progress Energy had outstanding short-term debt consisting primarily of commercial paper borrowings totaling $671 million at a weighted average interest rate of 0.50%.

At the end of each month during the three months ended December 31, 2011, Progress Energy had a maximum short-term debt balance of $671 million and an average short-term debt balance of $484 million at a weighted average interest rate of 0.45%. Progress Energy's short-term debt during the three months ended December 31, 2011, consisted primarily of commercial paper borrowings.

At the end of each month during the year ended December 31, 2011, Progress Energy had a maximum short-term debt balance of $671 million and an average short-term debt balance of $286 million at a weighted average interest rate of 0.40%. Progress Energy's short-term debt during the year ended December 31, 2011, consisted primarily of commercial paper borrowings.

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 produce substantially all of our consolidated cash from operations. 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, 2011, we have carried forward $865 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, availability under our credit facilities and issuances of commercial paper and long-term debt, which are dependent on our ability to successfully access capital markets. In the event the Merger does not close by the Merger Agreement termination date of July 8, 2012, we may also use equity offerings or ongoing sales of common stock through our IPP and/or employee benefit and stock option plans to support our liquidity requirements.

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 customers' future energy needs.

We typically issue commercial paper to meet short-term liquidity needs. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our RCAs, issuing short-term notes and/or issuing long-term debt.

The current RCA for the Parent expires in May 2013 and the current RCAs for PEC and PEF expire in October 2013. In the event we enter into new credit facilities for the Parent, PEC or PEF we cannot predict the terms, prices, duration or participants in such facilities (See "Credit Facilities and Registration Statements").

Progress Energy and its subsidiaries have approximately $12.941 billion in outstanding long-term debt, including the $950 million current portion at December 31, 2011. 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 lower our tax-exempt bond ratings. In the event of a two notch downgrade of PEC's and/or PEF's senior secured debt rating by S&P, the ratings of such utility's tax-exempt bonds would be below A-, likely resulting in higher future interest rate resets. In the event of a two notch downgrade by Moody's, PEC's tax-exempt bonds will continue to be rated at or above A3 while PEF's would be below A3, likely resulting in higher future interest rate resets for PEF's tax-exempt bonds. 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 contributions of $125 million to $225 million directly to pension plan assets in 2012 (See Note 17).

As discussed in "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 – Energy Demand," will require the Utilities to make significant capital investments. 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 will postpone major capital expenditures for the Levy project until after the NRC issues the COL, which is expected to be in 2013 if the current licensing schedule remains on track.

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, 2011, have impacted the amount of collateral posted with counterparties. At December 31, 2011, we had posted approximately $147 million of cash collateral compared to $164 million of cash collateral posted at December 31, 2010. The majority of our financial hedge agreements will settle in 2012 and 2013. 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. As discussed in Note 18C, 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.

The amount and timing of future sales of debt securities will depend on market conditions, operating cash flow and our specific liquidity needs. We may from time to time sell securities beyond the amount immediately needed to meet our capital or liquidity requirements in order to prefund our expected maturity schedule, 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, 2011, the current portion of our long-term debt was $950 million, including $500 million at PEC. We expect to fund the Parent's $450 million of Senior Notes due April 15, 2012, and PEC's $500 million of First Mortgage Bonds due July 15, 2012, with a combination of cash from operations, commercial paper borrowings and/or long-term debt issuances.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 8 and "Other Matters – Regulatory Environment," and 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. Energy legislation

enacted in recent years may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and EE.

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

PEC Cost-Recovery Filings

On June 29, 2011, the SCPSC approved PEC's request for an increase in the fuel rate charged to its South Carolina ratepayers. The $22 million increase, effective July 1, 2011, was driven by rising fuel prices.

On November 14, 2011, the NCUC approved a settlement agreement for an increase in the fuel rate PEC charges to its North Carolina ratepayers. The $85 million increase, effective December 1, 2011, was also driven by rising fuel prices.

Also on November 14, 2011, the NCUC approved PEC's request for an increase in the DSM and EE rate charges to its North Carolina ratepayers. The $24 million increase was effective December 1, 2011.

PEC Other Matters

The NCUC has issued Certificates of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 950-MW generating facility at a site in Wayne County, N.C., projected to be in service by January 2013 and an approximately 620-MW generating facility at a site in New Hanover County, N.C., projected to be in service by December 2013.

CR3 Outage

The preliminary cost estimate as filed with the FPSC on June 27, 2011, for the selected repair option to return CR3 to service is between $900 million and $1.3 billion. Engineering design of the final repair is under way. PEF will update the current estimate as this work is completed.

PEF maintains insurance for property damage and incremental costs of replacement power resulting from prolonged accidental outages through NEIL as discussed in Note 5D. NEIL has confirmed that the CR3 initial delamination is a covered accident but has not yet made a determination as to coverage for the second delamination. Following a 12-week deductible period, the NEIL program provided reimbursement for replacement power costs for 52 weeks at $4.5 million per week, through April 9, 2011. An additional 71 weeks of coverage, which runs through August 2012, is provided at $3.6 million per week. Accordingly, the NEIL program provides replacement power coverage of up to $490 million per event. Actual replacement power costs have exceeded the insurance coverage through December 31, 2011. PEF anticipates that future replacement power costs will continue to exceed the insurance coverage. PEF also maintains insurance coverage through NEIL's accidental property damage program, which provides insurance coverage up to $2.25 billion with a $10 million deductible per claim.

PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. PEF has not yet received a definitive determination from NEIL about the insurance coverage related to the second delamination. In addition, no replacement power reimbursements were received from NEIL in the second half of 2011. These considerations led us to conclude that at December 31, 2011, it was not probable that NEIL will voluntarily pay the full coverage amounts we believe they owe under the applicable insurance policies. Given the circumstances, accounting standards require full recovery to be probable to recognize an insurance receivable. Therefore, PEF has suspended recording any further insurance receivables from NEIL related to the second delamination and removed the associated $222 million NEIL receivable. PEF recorded a corresponding $154 million addition to its deferred fuel regulatory asset and a $68 million addition to construction work in progress. See "2012 Settlement Agreement" below for discussion of PEF's ability to recover prudently incurred fuel and purchased power costs and CR3 repair costs. Negotiations continue with NEIL regarding coverage associated with the second delamination and PEF continues to believe that all applicable costs associated with bringing CR3 back into service are covered under all insurance policies.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2011:

(in millions)	Replacement Power Costs	Repair Costs
Spent to date	$ 478	$ 258
NEIL proceeds received	(162)	(136)
Insurance receivable at December 31, 2011, net	(55)	(3)
Balance for recovery[(a)]	$ 261	$ 119

(a) See "2012 Settlement Agreement" and "PEF Cost Recovery Filings" below and Note 8C for discussion of PEF's ability to recover prudently incurred fuel and purchase power costs and CR3 repair costs.

PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. Additionally, we cannot be assured that CR3 can be repaired and brought back to service until full engineering and other analyses are completed.

PEF 2012 Settlement Agreement

On February 22, 2012, the FPSC approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The agreement, which will continue through the last billing cycle of December 2016, addresses three principal matters: cost recovery for Levy, the CR3 delamination prudence review pending before the FPSC and certain base rate issues. The agreement sets the Levy cost-recovery factor at a fixed amount during the term of the settlement and also allows PEF to recover investment and replacement power costs for CR3 in various circumstances. The parties to the agreement have waived or limited their rights to challenge the prudence of various costs related to CR3. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current ROE range of 9.5 percent to 11.5 percent. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. Additionally, PEF will refund $288 million to customers through the fuel clause over four years, beginning in 2013. See Note 8C for additional provisions of the 2012 settlement agreement.

PEF 2010 Settlement Agreement

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. Among other provisions, the settlement agreement also authorized PEF the opportunity to earn a ROE of up to 11.5 percent and provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited or interim base rate relief, or any combination thereof, subject to certain conditions. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been or are presently recovered through cost-recovery clauses or surcharges; or (b) that are incremental costs not currently recovered in base rates, which the legislature or FPSC determines are clause recoverable; or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis after depletion of the storm damage reserve. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period, PEF can begin recovery, subject to refund, through a surcharge of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement

allows PEF to use the surcharge to replenish the storm damage reserve to $136 million, the level as of June 1, 2010, after storm costs are fully recovered.

PEF Cost-Recovery Filings

On November 22, 2011, the FPSC approved a net increase of the total fuel-cost recovery by $162 million. The net increase, effective January 1, 2012, was driven primarily by rising fuel prices partially offset by lower anticipated costs associated with Levy and the deferral of 2011 and 2012 estimated costs associated with PEF's CR3 uprate project. Within the fuel clause, PEF received approval to collect, subject to refund, replacement power costs related to the CR3 nuclear plant outage.

On November 22, 2011, the FPSC approved PEF's request to increase the ECRC by $24 million, effective January 1, 2012.

CAPITAL EXPENDITURES

We expect to make significant capital investments to meet anticipated load growth and environmental standards. We are currently constructing new generating facilities in the Carolinas and potentially will construct new baseload generating facilities in the Carolinas and Florida that will be placed in service toward the middle of the next decade.

Total cash from operations and proceeds from long-term debt and equity issuances provided the funding for our 2011 capital expenditures, and those sources are expected to fund our forecasted capital expenditures.

As shown in the following table, we expect the majority of our capital expenditures to be incurred at our regulated operations. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2011**	2012	2013	2014
Regulated capital expenditures[a]	**$ 1,981**	$ 1,925	$ 1,920	$ 1,930
Nuclear fuel expenditures	**226**	160	220	255
AFUDC – borrowed funds	**(32)**	(35)	(30)	(20)
Other capital expenditures	**16**	30	30	30
Total before potential nuclear construction	**2,191**	2,080	2,140	2,195
Potential nuclear construction[b][c]	**63**	50-150	50-150	TBD
Total	**$ 2,254**	$ 2,130-2,230	$ 2,190-2,290	$ 2,195

[a] Excludes estimates for the repair of the CR3 containment building and the completion of the extended power uprate project.

[b] Expenditures for potential nuclear construction are net of AFUDC – borrowed funds.

[c] Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on the schedule shifts and other factors.

Regulated capital expenditures for 2012, 2013 and 2014 in the previous table include approximately $60 million, $95 million and $200 million, respectively, for environmental compliance. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance strategy and related recovery of costs. Regulated capital expenditures exclude estimates for the repair of the CR3 containment building and the completion of the extended power uprate project. Estimates of these projects will be developed upon the completion of ongoing engineering and project planning, the resolution of negotiations with NEIL regarding insurance coverage of the second CR3 delamination and final decisions regarding repair versus retirement.

Potential nuclear construction expenditures are primarily related to PEF's Levy project. Because of announced schedule shifts, we negotiated 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 announced schedule shift. Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on this and other factors. Future 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. These expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions (See Note 8C).

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, 2011 and 2010, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2011 and 2010, we had no outstanding borrowings under our credit facilities. We are required to pay fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

(in millions)		**Total**	**Outstanding**	**Reserved[a]**	**Available**
2011					
Parent	**Five-year (expiring 5/3/12)[b] [c]**	**$ 478**	**$ -**	**$ 252**	**$ 226**
PEC	**Three-year (expiring 10/15/13)**	**750**	**-**	**184**	**566**
PEF	**Three-year (expiring 10/15/13)**	**750**	**-**	**233**	**517**
Total credit facilities		**$ 1,978**	**$ -**	**$ 669**	**$ 1,309**
2010					
Parent	Five-year (expiring 5/3/12)	$ 500	$ -	$ 31	$ 469
PEC	Three-year (expiring 10/15/13)	750	-	-	750
PEF	Three-year (expiring 10/15/13)	750	-	-	750
Total credit facilities		$ 2,000	$ -	$ 31	$ 1,969

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011 and 2010, the Parent had issued $2 million and $31 million, respectively, of letters of credit supported by the RCA. On December 31, 2011, the Parent, PEC and PEF had $250 million, $184 million and $233 million, respectively, of outstanding commercial paper supported by their RCAs.

[b] Approximately $22 million of the $500 million expired May 3, 2011.

[c] On February 15, 2012, the Parent's $478 million credit facility was amended to extend the expiration date to May 3, 2013.

All of the revolving credit facilities were arranged through a syndication of financial institutions. See Note 12 for additional discussion of our credit facilities.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings. Fees and interest rates under our RCAs are based upon the respective credit ratings of the Parent's, PEC's and PEF's long-term unsecured senior noncredit-enhanced debt.

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, 2011. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2011, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 12.

On November 16, 2011, the Parent filed a shelf registration statement with the SEC for its IPP, which became effective upon filing with the SEC. The registration statement is effective for three years and registers 10 million

shares of common stock for issuance pursuant to the IPP. In addition, the Parent, as a well-known seasoned issuer, typically files a shelf registration statement with the SEC 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 and stock purchase units. Both PEC and PEF typically file shelf registration statements with the SEC under which they may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new combined shelf registration statement with the SEC, as our previously filed shelf registration statement for these securities expired November 17, 2011.

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 if certain conditions are satisfied. At December 31, 2011, PEC and PEF could issue up to approximately $6.8 billion and $2.9 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. Most first mortgage bond issuances by PEC and PEF require that adjusted net earnings be at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2011, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 5.0 times and 1.7 times, respectively. PEF's ratio of net earnings to the annual interest requirement for bonds outstanding, as defined in PEF's mortgage, was below 2.0 times at December 31, 2011. PEF's 2011 net earnings were impacted by a $288 million charge recorded in December 2011 for amounts to be refunded to customers (See Note 8C). Until this ratio, which is calculated based on results for 12 consecutive months, is above 2.0 times, PEF's capacity to issue first mortgage bonds is limited to $300 million based on retirements of previously issued first mortgage bonds. In the event PEF's long-term debt requirements exceed its first mortgage bond capacity, it could issue unsecured debt.

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, long-term debt, affiliate, current portion of long-term debt, short-term debt and capital lease obligations.

	2011	2010
Total equity	**41.9 %**	43.6 %
Preferred stock	**0.4 %**	0.4 %
Total debt	**57.7 %**	56.0 %

CREDIT RATING MATTERS

Our credit ratings reflect the current views of the rating agencies, and no assurances can be given that our 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.

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 customers' future energy needs (See Item 1A, "Risk Factors").

As discussed in Note 18C, 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.

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, 2011, we have issued $477 million of guarantees for future financial or performance assurance, including $19 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). 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, 2011, 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 18 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. 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, 2011, 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 (See Note 12)[a]	$ 12,999	$ 950	$ 1,130	$ 1,300	$ 9,619
Interest payments on long-term debt[b]	9,749	666	1,224	1,097	6,762
Capital lease obligations (See Note 22B)[c]	423	34	74	64	251
Operating leases (See Note 22B)[c]	1,400	67	193	186	954
Fuel and purchased power (See Note 22A)[d]	20,248	2,783	4,518	3,406	9,541
Other purchase obligations (See Note 22A)[e]	1,676	484	420	159	613
Minimum pension funding requirements[f]	423	119	208	88	8
Other postretirement benefits[g]	511	43	93	101	274
Uncertain tax positions[h]	-	-	-	-	-
Other commitments[i]	78	13	26	26	13
Total	$ 47,507	$ 5,159	$ 7,886	$ 6,427	$ 28,035

[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, 2011.

[c] Amounts include certain related executory cost commitments.

[d] Essentially all fuel and certain purchased power costs incurred by the Utilities are eligible for recovery through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support. Amounts exclude precedent and conditional contracts of $1.510 billion at PEC. (See Note 22A.)

[e] The future construction obligations presented in this table for Progress Energy exclude PEF's Levy EPC agreement. The EPC agreement includes provisions for termination. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. As discussed in Note 8C, in 2010 PEF identified a schedule shift in the Levy project, and major construction activities on Levy have been postponed until after the NRC issues the COL for the plants, which is expected in 2013 if the current licensing schedule remains on track. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges. Prior to the EPC amendment, estimated payments and associated escalations were $8.608 billion for the multi-year contract and did not assume any joint ownership. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict when those obligations will be satisfied or the magnitude of any change. PEF has continued with selected components of long lead time equipment. Work was suspended on the remaining long lead time equipment items, which have total remaining estimated payments and associated escalations of approximately $1.250 billion included in the previously discussed $8.608 billion. We cannot predict the outcome of this matter.

[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 and are subject to change based on factors such as experienced claims and general health care cost trends.

[h] Uncertain tax positions of $173 million are not reflected in this table as we cannot predict when open income tax years will close with completed examinations. It is reasonably possible that unrecognized tax benefits will decrease by approximately $25 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years.

[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

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. The table below summarizes the status of key environmental regulations that impact or may impact the Utilities. The table is followed by a detailed discussion of each regulation.

Status	Primarily Regulates	Compliance Strategy
	Impacting Solid Waste	
Coal Combustion Residuals		
Final rule expected in late 2012	Storage, use and disposal of coal ash and scrubber sludge	Proposed rule included two significantly different options. Compliance method cannot be determined until the rule is final.
	Impacting Air Quality	
NC Clean Smokestacks		
In effect	NOx, SO_2	Evaluating strategy for compliance subsequent to 2013
CAIR / CSAPR		
CAIR in effect pending resolution of appeal of CSAPR	NOx, SO_2	Previously installed air pollution controls and fleet modernization projects, and use of emission allowances
NC Mercury		
NC-specific requirements in effect	Mercury	Federal EGU MACT rule compliance
EGU MACT		
Final rule published February 16, 2012, and will become effective April 16, 2012	Mercury and other hazardous metals, acid gases, hydrogen fluoride, dioxin/furan	Previously installed air pollution controls and fleet modernization projects largely address for PEC; for PEF, additional controls and/or fleet modernization required
GHG New Source Performance Standards		
Proposed rule first quarter 2012	GHGs	Case-by-case determination for new units
CAVR – BART provisions		
Effective 2013	NOx, SO_2 and particulate matter	Assessing BART impact; EPA may allow CSAPR compliance to fulfill BART requirements
NAAQS		
In effect	Ozone, NO_2, SO_2 and particulate matter	Currently in compliance. Additional controls may be necessary if nonattainment is determined

Impacting Water Quality		
316(b)		
Final rules are expected in late July 2012	Cooling water intake structures for steam-electric power plants	Modification of traveling screens; assessment of environmental impacts and alternative technologies for reducing those impacts; and possible installation of new technologies
Effluent Guideline Revisions		
Proposed revisions anticipated in late July 2012	Wastewater discharges from steam-electric plants	Cannot be determined until final rule is issued

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the 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 8 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.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residuals, 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. In 2010, the EPA proposed two options for new rules to regulate coal combustion residuals. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residuals management and disposal under federal hazardous waste rules. The other option would have the EPA set performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste (as most states do now). The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. A final rule is expected in 2012. 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. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

AIR 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 expense. Control equipment installed for compliance with then-existing or proposed laws and regulations, which are discussed below, may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

The 2002 enactment of the Clean Smokestacks Act requires 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 affected by the Clean Smokestacks Act. PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEC implemented a plan to retire, by the end of 2013, its coal-fired generating facilities in North Carolina (originally totaling 1,500 MW) that do not have scrubbers and replace the generation capacity with new natural gas-fueled generating facilities, which should enable the utility to comply with the final Clean Smokestacks Act SO_2 emissions target that begins in 2013. The first unit was retired in 2011. We anticipate that PEC will maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expense increases 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; the North Carolina retail portion of all other O&M expense is currently recoverable through base rates. In 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 O&M expense that PEC incurs in connection with its environmental compliance control facilities.

Clean Air Interstate Rule/Cross-State Air Pollution Rule

The CAIR, issued by the EPA, 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. A 2008 decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) remanded the CAIR without vacating it for the EPA to conduct further proceedings.

On July 7, 2011, the EPA issued the CSAPR to replace the CAIR. The CSAPR, slated to take effect on January 1, 2012, contains new emissions trading programs for NOx and SO_2 emissions as well as more stringent overall emissions targets in 27 states, including North Carolina, South Carolina and Florida. A number of parties, including groups which PEC and PEF are members of, filed petitions for reconsideration and stay of, as well as legal challenges to, the CSAPR. On December 30, 2011, the D.C. Court of Appeals issued an order staying the implementation of the CSAPR, pending a decision by the court resolving the challenges to the rule. Oral argument for the CSAPR litigation has been scheduled for April 13, 2012. As a result of the stay of CSAPR, the CAIR will remain in effect. The EPA issued the CSAPR as four separate programs, including the NOx annual trading program, the NOx ozone season trading program, the SO_2 Group 1 trading program and the SO_2 Group 2 trading program. If the CSAPR is upheld, North Carolina and South Carolina are included in the NOx and SO_2 annual trading programs, as well as the NOx ozone season program. North Carolina remains classified as a Group 1 state, which will require additional NOx and SO_2 emission reductions beginning in January 2014. South Carolina remains classified as a Group 2 state with no additional reductions required. Under the CSAPR, Florida is subject only to the NOx ozone season program. We cannot predict the outcome of this matter.

Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures. The air quality controls installed to comply with NOx and SO_2 requirements under certain

sections of the Clean Air Act (CAA) and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR and CSAPR requirements for NOx and SO_2 for our North Carolina units at PEC. NOx and SO_2 emission control equipment are in service at PEF's Crystal River Unit No. 4 and Crystal River Unit No. 5 (CR4 and CR5), and we plan to continue compliance with the CAIR in 2012 through a combination of emission controls, continued use of natural gas at applicable facilities and use of emission allowances.

Under an agreement with the Florida Department of Environmental Protection (FDEP), PEF will retire Crystal River Units No. 1 and No. 2 coal-fired steam units (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 originally anticipated to be around 2020. As discussed in Note 8C and "Other Matters – Nuclear – Potential New Construction," major construction activities for Levy are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

Mercury Regulation

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it would develop MACT standards. The U.S. District Court for the District of Columbia issued an order requiring the EPA to issue a final MACT standard for power plants. On February 16, 2012, the EPA published the final EGU MACT. The rule will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. The EGU MACT contains stringent emission limits for mercury, non-mercury metals and acid gases from coal-fired units and hazardous air pollutant metals, acid gases and hydrogen fluoride from oil-fired units. 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. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. We are continuing to evaluate the impacts of the EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC. The outcome of these matters cannot be predicted.

Clean Air Visibility Rule

The EPA's Clean Air Visibility Rule (CAVR) 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 certain 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 best available retrofit technology (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 in Note 8B, Sutton Unit No. 3 is one of the coal-fired generating units that PEC plans to replace with combined cycle natural gas-fueled electric generation. As discussed previously, 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' decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for NOx and SO_2. In addition, the EPA has indicated that it intends to finalize a rule by spring 2012 that addresses its determination whether, for power plants, meeting the requirements in the CSAPR will fulfill the BART requirements for SO_2 and NOx under the regional haze program. Under subsequent implementation of CSAPR, CAVR compliance eventually will require consideration of SO_2 emissions in addition to particulate matter emissions for PEF's BART-eligible units, because Florida will no longer be subject to the current CAIR SO_2 emissions

provisions. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. 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, in the spring of 2010 the EPA indicated that the Reasonable Further Progress portion of the Regional Haze implementation rule is not approvable. The FDEP is in the process of amending the rule by removing the Reasonable Further Progress provision, including the December 31, 2017 deadline for installation of additional controls, and instead will rely on current federal programs to achieve improvement in visibility. In November 2011, the EPA announced a settlement that sets a schedule for action on the regional haze state implementation plans submitted by the states. The deadlines in the consent decree provide that all final EPA actions on the regional haze state implementation plans are to occur no later than November 15, 2012. 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 CSAPR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with NOx and SO_2 requirements under certain sections of the CAA and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, resulted in a reduction of the costs to meet PEC's CAIR and CSAPR requirements.

PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions and PEF's environmental compliance projects under the first phase of CAIR are in service.

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 previous discussion regarding the vacating of the CAMR and remanding of the CAIR and its potential impact on CAVR). PEF's April 1, 2011 filing with the FPSC for true-up of final 2010 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and total estimated project cost of approximately $1.1 billion to plan, design, build and install pollution control equipment at CR4 and CR5, which has been placed in service. PEF does not currently plan to install air pollution control equipment at the Anclote Plant as previously anticipated in its approved Integrated Clean Air Compliance Plan. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed previously, or to meet compliance requirements of the CSAPR. 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

Risk factors regarding environmental compliance cost estimates are discussed in Item 1A, "Risk Factors." 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. 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. Additional compliance plans for PEC and PEF to meet the requirements of the CSAPR have not been completed. Compliance plans and costs to meet the requirements of the CAVR are being reassessed, and we cannot predict the impact that the EPA's further proceedings will have on our compliance with the CAVR requirements. Compliance plans to meet the requirements of the EGU MACT are being developed. Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act (Section 316(b)), as discussed below, will be determined upon finalization of the rule. The timing and extent of the costs for future projects will depend upon final compliance strategies. However, we believe that future costs to comply with new or subsequent rule interpretations could be significant.

North Carolina Attorney General Petition under Section 126 of the Clean Air Act

In 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the CAA, 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

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. In 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. In November 2011, environmental groups petitioned the court to require the EPA to issue a proposal regarding reconsideration of the standards by February 15, 2012, and issue a final rule by September 15, 2012. On January 23, 2012, the EPA replied to the petition with a schedule that would require the agency to issue a proposed rule by June 2012 and a final rule by June 2013. 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. 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 2009, the EPA announced that it was reconsidering the level of the ozone NAAQS and it will stay plans to designate nonattainment areas until after the reconsideration has been completed.

In 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. On September 2, 2011, President Obama announced that the EPA would withdraw the proposed revision. As a result, the ozone NAAQS promulgated in 2008 will be implemented, and the review of the standard has been deferred until 2013. With respect to the 2008 standard, all areas in our service territories are currently in compliance.

In 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide (NO_2). Currently, there are no monitors reporting violation of this new standard in our service territories, but an expanded monitoring network will provide additional data, which could result in additional nonattainment areas. Additionally, the EPA revised the 1-hour NAAQS for SO_2 in 2010. Implementation of the new 1-hour NAAQS for SO_2 uses air quality modeling along with monitoring data in determining whether areas are attaining the new standard, which is likely to expand the number of nonattainment areas. No additional nonattainment areas have been designated to date in our service territories. Should additional nonattainment areas for the NAAQS for NO_2 and SO_2 be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of these matters cannot be predicted.

On July 13, 2011, the EPA made available its proposed action on the combined review of the secondary NAAQS for NOx and sulfur oxides (SOx) and expects to issue a final rule by March 2012. In this rulemaking, the EPA is proposing to retain the existing secondary standards for NO_2 and SO_2 and is also proposing a new set of secondary standards identical to the health-based primary standards it set in 2010. For NOx, the new standard would be 100 parts per billion averaged over one hour, measured as NO_2. For SOx, the new standard would be 75 parts per billion averaged over one hour, measured as SO_2. Should nonattainment areas for secondary NAAQS for NOx and SOx be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of these matters cannot be predicted.

WATER QUALITY

General

As a result of the operation of certain pollution control equipment required to address the air quality issues outlined previously, 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.

In 2009, the EPA concluded after a multi-year study of power plant wastewater discharges that 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.

More stringent effluent limitations contained in the current water discharge permit for the Mayo Steam Electric Plant became effective in June 2011. PEC is currently negotiating the issuance of a special order by consent with the North Carolina Division of Water Quality, which would defer the agency's enforcement of the more stringent effluent limitations due to the plant's inability to achieve compliance with those limitations. The special order by consent, if issued, is expected to include the required development and installation of enhanced water pollution control technology and application of less stringent interim effluent limitations until PEC's planned project to bring the plant into compliance with the more stringent effluent limitations is completed. However, since the special order by consent has not yet been issued in final form, it is not possible to determine the extent of the planned project. Moreover, the special order by consent does not prevent actions by the EPA or third parties. Thus, the outcome of these matters cannot be determined.

On October 5, 2011, Earthjustice, on behalf of the Sierra Club and Florida Wildlife Federation, filed a petition seeking review of the water discharge permit issued to CR1, CR2 and CR3 (See Note 22D).

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 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. Following appeal, in 2009, the U.S. Supreme Court issued an 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. In December 2010, consent decrees were entered in two pending federal actions brought by environmental groups against the EPA requiring the EPA to issue proposed Section 316(b) rules by March 28, 2011, and to issue a final decision by July 27, 2012.

On April 20, 2011, the EPA published its proposed regulations for cooling water intake structures at existing power generating, manufacturing and industrial facilities that withdraw more than two million gallons of water per day from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed regulations would establish nationwide, uniform standards for impingement mortality (immobilization of

aquatic organisms against an intake screen) and case-by-case, site-specific standards for entrainment mortality (lethal effects due to passage of aquatic organisms into a cooling system). Comments on the proposed rule have been timely submitted by affected parties, including PEC and PEF. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

State, federal and international attention to global climate change is expected to result in the regulation of CO_2 and other GHGs. 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 our service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative and renewable energy and a state-of-the-art power system.

The EPA has begun the process of regulating GHG emissions through use of the CAA. In 2007, the U.S. Supreme Court ruled that the EPA has the authority under the CAA to regulate CO_2 emissions from new automobiles. According to the EPA this also results in stationary sources, such as coal-fired power plants, being subject to regulation of GHG emissions under the CAA. In 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 CAA. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of regulation under GHG initiatives and any final legislation, if enacted, 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.

In 2010, the EPA announced a schedule for development of a new source performance standard for new and existing fossil fuel-fired electric utility units. Under the schedule, the EPA was to propose the standard by September 30, 2011, and issue the final rule by May 2012. The EPA is now expected to propose the standard in the first quarter of 2012.

The EPA issued the final "tailoring rule," which establishes the thresholds for applicability of the Prevention of Significant Deterioration program permitting requirements for GHG emissions from stationary sources such as power plants and manufacturing facilities. Prevention of Significant Deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. The tailoring rule initially raises the permitting applicability threshold for GHG emissions to 75,000 tons per year. These developments require PEC and PEF to address GHG emissions in new air quality permits. The permitting requirements for GHG emissions from stationary sources began on January 2, 2011. A number of parties have filed petitions for review of the tailoring rule in the D.C. Court of Appeals. The impact of these developments cannot be predicted.

In 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 annual emissions by March 31 of the following year. The reporting requirements began in 2011 with year 2010 emissions and we complied with the requirement of the reporting rule. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was originally adopted by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect in 2005, the United States has not ratified it. In 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. In 2010, President Obama submitted a proposal to Congress to reduce the U.S. GHG emissions in

the range of 17 percent below 2005 levels by 2020, subject to future congressional action. To date, Congress has not enacted legislation implementing the president's proposal.

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.

In May 2011, PEC and PEF were named, along with numerous other defendants, in a complaint of a class action lawsuit. Plaintiffs claim that defendants' GHG emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. We cannot predict the outcome of this matter (See Note 22C).

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 the opportunity 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 if any of these states will move to increase retail competition in the electric industry.

Current retail rate matters affected by state regulatory authorities are discussed in Notes 8B and 8C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

On April 28, 2010, we accepted a grant from the DOE for $200 million in federal matching infrastructure funds. In addition to providing the Utilities real-time information about the state of their electric grids, the smart grid transition will enable customers to better understand and manage their energy use, and will provide for more efficient integration of renewable energy resources. Supplementing the DOE grant, the Utilities will invest more than $300 million in smart grid projects, which include enhancements to distribution equipment, installation of 160,000 additional smart meters and additional public infrastructure for plug-in electric vehicles. Projects funded by the grant must be completed by April 2013.

Through December 31, 2011, we have incurred $225 million of allowable, 50 percent reimbursable, smart grid project costs, and have submitted to the DOE requests for reimbursement of $112 million, of which we have received $89 million.

Concerns about climate change and oil price volatility have led to proposed and enacted legislation at the federal and state levels to increase renewable energy and GHG emissions.

The NC REPS requires PEC to file an annual 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 earned after January 1, 2008. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, are participating in the renewable energy certificate tracking system, which came online July 1, 2010. North Carolina law mandates that utilities achieve a targeted amount of energy from specified renewable energy resources or implementation of energy-efficiency measures beginning with a 3 percent requirement in 2012 escalating to 12.5 percent in 2021. PEC expects to be in compliance with this requirement.

In 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders include adoption of a maximum allowable emissions level of GHGs for Florida utilities, which 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 executive orders also requested that the FPSC initiate a rulemaking 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).

In response to the executive orders, Florida energy law enacted in 2008 includes provisions that required the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification and also includes provisions that direct the 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. To date, the Florida legislature has not ratified or enacted any renewable portfolio standard or cap-and-trade rules or programs. Until these agency actions are finalized, we cannot predict the outcome of this matter.

Our balanced solution, as described in "Energy Demand," demonstrates our commitment to environmental responsibility.

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) energy efficiency; (2) alternative and renewable energy; and (3) a state-of-the-art power system.

We are continuing the expansion and enhancement of our DSM and EE 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. Our previously discussed smart grid projects will aid in these initiatives. EE programs include any equipment, physical or program change that results in less energy used to perform the same function. We provide our residential customers with home energy audits and offer EE 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 website with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative and renewable energy projects to pursue the generation of electricity from biomass, solar, hydrogen and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 350 MW of electricity generated from biomass, including over 200 MW for compliance with NC REPS. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 30 MW of electricity generated from solar photovoltaic generation, with the majority purchased for compliance with NC REPS. Of the 30 MW of purchased solar photovoltaic generation, 12 MW are online and the remainder is expected to come online during 2012. Additionally, customers across our service territory have connected more than 11 MW of solar photovoltaic energy systems to our grid. Progress Energy offers a range of solar incentives and programs, which have increased, and will continue to significantly increase, our use of solar energy over the next decade.

We are pursuing numerous options to create a state-of-the-art power system, including investments in smart grid technology and advanced environmental controls on our coal-fired plants. In the coming years, we will continue to invest in existing nuclear plants and evaluate plans for building or co-owning new generating plants. Due to the anticipated long-term growth in our service territories, retirement of existing coal generation and potential changes in environmental regulations, we are constructing new natural gas-fueled generating facilities in the Carolinas and we estimate that we will require new generating facilities in both Florida and the Carolinas in the first half of the next decade. In addition to nuclear generation, we are evaluating natural gas-fired plants, renewable generation resources, energy-efficiency initiatives and economic purchased power to meet this increased need. At this time, no

definitive decisions have been made to construct or when to construct our proposed new nuclear plants (See "Nuclear – Potential New Construction") or to acquire new generation from another utility's regional nuclear project. In the near term, we will focus our efforts on modernizing the power system and pursuing all elements of a balanced portfolio while looking to new nuclear capacity as a critical part of the long-term mix.

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 original strategy called for the retirement of the coal-fired units by the end of 2017; however, we currently expect the plants will be retired no later than the end of 2013. PEC has received approval from the NCUC for construction of an approximately 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 also received approval from the NCUC to construct an approximately 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C., to replace the existing coal-fired generation at this site. The facility is projected to be placed in service in December 2013. After 2013, PEC will continue to operate its Roxboro, Mayo and Asheville coal-fired plants in North Carolina, which have state-of-the-art emission controls. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at these sites.

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.

In light of the events at the Fukushima Daiichi nuclear power station in Japan, the NRC formed a task force to conduct a comprehensive review of processes and regulations to determine whether the agency should make additional improvements to the nuclear regulatory system. On July 13, 2011, the task force proposed a set of improvements designed to ensure protection, enhance accident mitigation, strengthen emergency preparedness and improve efficiency of NRC programs. The NRC is also expected to issue a longer-term report with recommendations for the Commission's consideration by early 2012. With the ongoing investigations into the nature and extent of damages in Japan, the underlying causes of the situation and the lack of clarity around regulatory and political responses, we cannot predict to what extent the NRC will impose additional licensing and safety-related requirements. See Item 1A, "Risk Factors."

In September 2009, CR3 began an outage for normal refueling and maintenance, as well as its uprate project to increase its generating capacity and to replace two steam generators. During preparations to replace the steam generators, we discovered a delamination within the concrete of the outer wall of the containment structure, which has resulted in an extension of the outage. After a comprehensive analysis, we have determined that the concrete delamination at CR3 was caused by redistribution of stresses on the containment wall that occurred when we created an opening to accommodate the replacement of the unit's steam generators. In March 2011, engineers investigated and subsequently determined that a new delamination had occurred in another area of the structure after initial repair work was completed and during the late stages of retensioning the containment building. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process. Engineering design of the repair is under way. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments. (See Note 8C).

PEC's nuclear units have operating licenses granted by the NRC that have been renewed to 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, when 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. The NRC's remaining open items in the license renewal review process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

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 estimated 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.

In 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. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. 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 the Levy nuclear project application. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL.

PEF's initial schedule anticipated performing certain site work pursuant to the Limited Work Authorization prior to COL receipt. However, in 2009, the NRC staff determined that certain schedule-critical work that PEF had proposed to perform within the scope of the Limited Work Authorization will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance, which is expected in 2013 if the current licensing schedule remains on track. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated timeframe. Since then, regulatory and economic conditions have changed, resulting in additional schedule shifts. These conditions include the permitting and licensing process, national and state economic conditions, short-term natural gas prices and other FPSC decisions. Uncertainty regarding PEF's access to capital on reasonable terms, PEF's ability to secure joint owners and increasing uncertainty surrounding carbon regulation and its costs could be other factors to affect the Levy schedule.

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 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 executed an amendment to the EPC agreement in 2010 due to the schedule shifts previously discussed. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges.

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 included 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. PEF's 2011 nuclear cost-recovery filing included an updated analysis that demonstrated continued feasibility of the Levy project with PEF's current estimated range of total escalated cost, including transmission, of $17.2 billion to $22.5 billion. The filed estimated cost range primarily reflects cost escalation resulting from the schedule shifts. Many factors will affect the total cost of the project and once PEF receives the COL, it will further refine the project timeline and budget. As previously discussed, we continue to evaluate the Levy project on an ongoing basis.

In 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 the Harris 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 the middle of the next decade (See "Energy Demand" above).

SPENT NUCLEAR FUEL MATTERS

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

SYNTHETIC FUELS TAX CREDITS

Historically, we had substantial operations associated with the production and sale of coal-based solid synthetic fuels, which qualified for federal income tax credits so long as certain requirements were satisfied. Tax 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 $1.026 billion has been used through December 31, 2011, to offset regular federal income tax liability and $865 million is being carried forward as deferred tax credits that do not expire.

See Note 22D and Item 1A, "Risk Factors," for additional discussion related to our previous synthetic fuels operations and the associated tax credits generated under the synthetic fuels tax credit program.

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 3 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, 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 and borrow from, but not lend to, the Parent.

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

PEC expects to have sufficient resources to meet its future obligations through a combination of cash from operations, availability under its credit facility, money pool borrowings, issuances of commercial paper and long-term debt and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

Cash Flows from Operations

Net cash provided by operating activities decreased $381 million for 2011, when compared to 2010. The decrease was primarily due to $269 million higher cash used for inventory, a $122 million increase in pension plan funding, the $107 million less favorable impact of weather as previously discussed and $33 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011, partially offset by $205 million in lower net cash for taxes. The increase in cash used for inventory was primarily due to higher coal purchases in 2011 reflecting anticipated winter consumption and inventory levels that remained high at year-end (due to lower natural gas prices) combined with higher 2010 consumption of existing inventory levels to meet system requirements resulting from favorable weather.

Net cash provided by operating activities increased $235 million in 2010, when compared to 2009. The increase was primarily due to the $115 million favorable impact of weather partially offset by $78 million higher nuclear plant outage and maintenance costs included in O&M, both as previously discussed; $141 million lower cash used for inventory, primarily due to higher coal consumption as a result of favorable weather in 2010 that was fulfilled through the 2010 usage of inventory from year-end 2009; $86 million lower cash used for pension and other benefits primarily due to a reduction of contributions made in 2010; and $37 million lower cash paid for income taxes. These amounts were partially offset by a $108 million decrease in the over-recovery of fuel as a result of higher fuel costs in 2010.

Investing Activities

Net cash used by investing activities increased $239 million in 2011, when compared with 2010. The increase was primarily due to a $200 million change in advances to affiliated companies.

Net cash used by investing activities increased $67 million in 2010, when compared with 2009. The increase was primarily due to a $359 million increase in gross property additions and a $61 million increase in nuclear fuel additions, partially offset by a $351 million decrease in advances to affiliated companies. The increase in property

additions is primarily due to increased capital expenditures at the Wayne County, New Hanover County and Harris generating facilities. The increase in nuclear fuel additions was primarily due to the three nuclear refueling and maintenance outages in 2010, compared to two in 2009.

Financing Activities

Net cash provided by financing activities increased $215 million for 2011, when compared to 2010. The increase was primarily due to the $500 million issuance of first mortgage bonds in 2011 and $185 million in commercial paper borrowings in 2011, partially offset by the $585 million payment of dividends to the Parent in 2011 compared to $100 million in 2010.

Net cash used by financing activities decreased $10 million for 2010, when compared to 2009. The decrease was primarily due to the $400 million payment at maturity of long-term debt in 2009, the $110 million net repayment of commercial paper in 2009 and a $100 million reduction in dividends paid to the Parent in 2010 compared to 2009. These impacts were partially offset by $600 million issuance of first mortgage bonds in 2009.

On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

On October 15, 2010, PEC entered into a new $750 million, three-year RCA with a syndication of 22 financial institutions. The RCA is used to provide liquidity support for PEC's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCA will expire on October 15, 2013. The prior $450 million RCA was terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").

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 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.

SHORT-TERM DEBT

At December 31, 2011, PEC had an outstanding short-term debt balance consisting primarily of commercial paper borrowing totaling $219 million at a weighted average interest rate of 0.51%.

At the end of each month during the three months ended December 31, 2011, PEC had a maximum short-term debt balance of $219 million and an average short-term debt balance of $73 million at a weighted average interest rate of 0.51%. PEC's short-term debt during the three months ended December 31, 2011, consisted primarily of commercial paper and money pool borrowings.

At the end of each month during the year ended December 31, 2011, PEC had a maximum short-term debt balance of $219 million and an average short-term debt balance of $83 million at a weighted average interest rate of 0.39%. PEC's short-term debt during the year ended December 31, 2011, consisted primarily of commercial paper and money pool borrowings.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2012, 2013 and 2014 are approximately $1.4 billion, $1.3 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 cash from operations, issuance of long-term debt and/or contributions of equity from the Parent. In addition, PEC has a $750 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.

At December 31, 2011, the current portion of PEC's long-term debt was $500 million. We expect to fund the $500 million of First Mortgage Bonds, due July 15, 2012, with a combination of cash from operations, commercial paper borrowings and/or long-term debt.

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, including new generating facilities in the Carolinas currently under construction and the potential for additional new baseload generating facilities toward the middle 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 typically files a shelf registration statement with the SEC under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new shelf registration statement with the SEC, as PEC's previously filed shelf registration statement for these securities expired November 17, 2011. (See "Credit Facilities and Registration Statements.")

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, current portion of long-term debt and capital lease obligations.

	2011	2010
Total equity	**53.2 %**	57.9 %
Preferred stock	**0.6 %**	0.7 %
Total debt	**46.2 %**	41.4 %

See the discussion of PEC's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 12 for further information regarding PEC'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 PEC's off-balance sheet arrangements and contractual obligations at December 31, 2011.

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

CONTRACTUAL OBLIGATIONS

PEC is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. 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 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, 2011, 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 (See Note 12)[a]	$ 4,199	$ 500	$ 405	$ 700	$ 2,594
Interest payments on long-term debt[b]	1,794	193	301	235	1,065
Capital lease obligations (See Note 22B)	18	2	10	-	6
Operating leases (See Note 22B)[c]	764	29	96	97	542
Fuel and purchased power (See Note 22A)[d]	6,838	1,252	1,864	1,482	2,240
Other purchase obligations (See Note 22A)	913	354	230	87	242
Minimum pension funding requirements[e]	183	61	93	29	-
Other postretirement benefits[f]	244	19	43	48	134
Uncertain tax positions[g]	-	-	-	-	-
Other commitments[h]	78	13	26	26	13
Total	$ 15,031	$ 2,423	$ 3,068	$ 2,704	$ 6,836

(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, 2011.

(c) Amounts include certain related executory cost commitments.

(d) Essentially all of PEC's fuel and certain purchased power costs are eligible for recovery through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support. Amounts exclude precedent and conditional contracts of $1.510 billion. (See Note 22A.)

(e) Represents the projected minimum required contributions to the qualified pension trust 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 and are subject to change based on factors such as experienced claims and general health care cost trends.

(g) Uncertain tax positions of $73 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, 2012.

(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, 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 and borrow from, but not lend to, the Parent.

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

PEF expects to have sufficient resources to meet its future obligations through a combination of cash from operations, availability under its credit facility, money pool borrowings, issuances of commercial paper and long-term debt and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2011 AS COMPARED TO 2010 AND 2010 AS COMPARED TO 2009

Cash Flows from Operations

Net cash provided by operating activities decreased $439 million for 2011, when compared to 2010. The decrease was primarily due to $161 million lower recovery of capacity costs, the $112 million less favorable impact of weather as previously discussed, a $78 million increase in pension plan funding, $72 million decrease in NEIL reimbursements for CR3 replacement power costs and $33 million paid for interest rate hedges terminated in conjunction with the issuance of long-term debt in 2011. The change in recovery of capacity costs in 2011 was primarily due to the $51 million refund of prior-year over-recovery of capacity costs and the 2010 collection of $110 million of previously under-recovered capacity costs.

Net cash provided by operating activities increased $67 million in 2010, when compared with 2009. The increase was primarily due to the $88 million favorable impact of weather as previously discussed; $98 million net cash receipts from income taxes in 2010 compared to $184 million of net cash payments for income taxes in 2009; and $56 million lower cash used for inventory, primarily due to higher coal consumption in 2010 as a result of favorable weather that was fulfilled through 2010 usage of inventory from year-end 2009. These amounts were partially offset by an $81 million under-recovery of fuel in 2010 compared to a $103 million over-recovery of fuel in 2009 driven by lower fuel rates in 2010 and $6 million of net payments of cash collateral to counterparties on derivative contracts in 2010 compared to $190 million net refunds of cash collateral in 2009.

Investing Activities

Net cash used by investing activities decreased $280 million in 2011, when compared with 2010. The decrease was primarily due to a $198 million decrease in gross property additions, primarily due to lower spending for environmental compliance and nuclear projects; $27 million of litigation judgment proceeds; and $24 million increase in receipt of smart grid grant reimbursement.

Net cash used by investing activities decreased $541 million in 2010, when compared with 2009. The decrease was primarily due to a $435 million decrease in gross property additions and a $64 million increase in cash provided by insurance proceeds. The decrease in property additions was driven by decreases in environmental compliance spending and expenditures for nuclear projects. The increase in cash provided by insurance proceeds is driven by the receipt of NEIL insurance proceeds for repairs due to the CR3 extended outage.

Financing Activities

Net cash used by financing activities increased $306 million for 2011, when compared to 2010. The increase was primarily due to the combined $600 million issuance of first mortgage bonds in March 2010 and the $460 million increase in payment of dividends to the Parent in 2011, partially offset by a $300 million issuance of first mortgage bonds in August 2011, $233 million of commercial paper borrowings in 2011 and the $211 million change in advances from affiliated companies.

Net cash provided by financing activities decreased $374 million for 2010, when compared to 2009. The decrease was primarily due to a $620 million contribution from the Parent in 2009, a $361 million decrease in advances from affiliates and a $300 million retirement at maturity of long-term debt in 2010. The decreases are partially offset by the $600 million issuance of first mortgage bonds in 2010 and $371 million repayment of commercial paper in 2009.

On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt borrowings.

On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due 2020 and $350 million of 5.65% First Mortgage Bonds due 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

On October 15, 2010, PEF entered into a new $750 million, three-year RCA with a syndication of 22 financial institutions. The RCA is used to provide liquidity support for PEF's issuances of commercial paper and other short-term obligations, and for general corporate purposes. The RCA will expire on October 15, 2013. The prior $450 million RCA was terminated effective October 15, 2010 (See "Credit Facilities and Registration Statements").

In 2009, PEF did not issue or retire long-term debt.

SHORT-TERM DEBT

At December 31, 2011, PEF had outstanding short-term debt consisting primarily of commercial paper borrowings totaling $241 million at an interest rate of 0.51 percent.

At the end of each month during the three months ended December 31, 2011, PEF had a maximum short-term debt balance of $249 million and an average short-term debt balance of $179 million at a weighted average interest rate of 0.46 percent. PEF's short-term debt during the three months ended December 31, 2011, included only commercial paper and money pool borrowings.

At the end of each month during the year ended December 31, 2011, PEF had a maximum short-term debt balance of $350 million and an average short-term debt balance of $106 million at a weighted average interest rate of 0.40 percent. PEF's short-term debt during the year ended December 31, 2011, included only commercial paper and money pool borrowings.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2012, 2013 and 2014 are approximately $720 million to $820 million, $830 million to $930 million, and $760 million, respectively, and primarily reflect construction expenditures to

support customer growth, add regulated generation and upgrade existing facilities, as discussed in Progress Energy "Capital Expenditures." PEF's estimated capital requirements for 2012 and 2013 include potential nuclear construction expenditures, primarily related to PEF's Levy project. Because of announced schedule shifts, we negotiated an amendment to the Levy EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction"). The forecasted capital expenditures reflect the announced schedule shift. Project spending for 2014 and beyond will be determined once the timing for the receipt of the COL is known and more detailed estimates have been developed based on this and other factors. Future 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. These expenditures are subject to cost-recovery provisions in PEF's jurisdiction (See Note 8C).

PEF's estimated capital expenditures exclude estimates for the repair of the CR3 containment building and the completion of the extended power uprate project. Estimates of these projects will be developed upon the completion of ongoing engineering and project planning, the resolution of negotiations with NEIL regarding insurance coverage of the second CR3 delamination, and final decisions regarding repair versus retirement.

PEF expects to fund its capital requirements primarily through a combination of cash from operations, issuance of long-term debt and/or contributions of equity from the Parent. In addition, PEF has a $750 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.

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 generating facilities in Florida toward the middle of the next decade. 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 typically files a shelf registration statement with the SEC under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock. We expect to file a new shelf registration statement with the SEC, as PEF's previously filed shelf registration statement for these securities expired November 17, 2011 (See "Credit Facilities and Registration Statements").

CAPITALIZATION RATIOS

The following table shows each component of capitalization as a percentage of total capitalization at December 31, 2011 and 2010. In addition to total equity and preferred stock, total capitalization includes the following in total debt: long-term debt, net, current portion of long-term debt, notes payable to affiliated companies and capital lease obligations.

	2011	2010
Total common stock equity	**48.5 %**	50.9 %
Preferred stock	**0.4 %**	0.3 %
Total debt	**51.1 %**	48.8 %

See the discussion of PEF's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 12 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, 2011.

MARKET RISK AND DERIVATIVES

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

CONTRACTUAL OBLIGATIONS

This information called for by Item 7 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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 18). 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 may have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 11 percent and 7 percent of consolidated debt had variable rates at December 31, 2011 and 2010, respectively.

Based on our variable rate long-term and short-term debt balances at December 31, 2011, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $15 million. We had $671 million of outstanding short-term debt at December 31, 2011.

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, 2011 and 2010, 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 Parent-obligated mandatorily redeemable preferred 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 2012 to 2016 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 18 for more information on interest rate derivatives.

December 31, 2011								**Fair Value December 31,**
(dollars in millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**2011**
Fixed-rate long-term debt	**$ 950**	**$ 830**	**$ 300**	**$ 1,000**	**$ 300**	**$ 8,449**	**$ 11,829**	**$ 14,128**
Average interest rate	**6.67 %**	**4.96 %**	**6.05 %**	**5.18 %**	**5.63 %**	**5.80 %**	**5.76 %**	
Variable-rate long-term debt	**-**	**-**	**-**	**-**	**-**	**$ 861**	**$ 861**	**$ 861**
Average interest rate	**-**	**-**	**-**	**-**	**-**	**0.30 %**	**0.30 %**	
Debt to affiliated trust[a]	**-**	**-**	**-**	**-**	**-**	**$ 309**	**$ 309**	**$ 318**
Interest rate	**-**	**-**	**-**	**-**	**-**	**7.10 %**	**7.10 %**	
Interest rate forward contracts[b]	**$ 400**	**$ 100**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 500**	**$ (93)**
Average pay rate	**4.23 %**	**4.37 %**	**-**	**-**	**-**	**-**	**4.26 %**	
Average receive rate	**[c]**	**[c]**	**-**	**-**	**-**	**-**	**[c]**	

[a] Florida Progress Funding Corporation - Junior Subordinated Deferrable Interest Notes.

[b] Notional amounts 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 0.58% at December 31, 2011.

At December 31, 2011, Progress Energy had $500 million notional of open forward starting swaps, including $250 million notional at PEC and $50 million notional at PEF.

December 31, 2010								Fair Value December 31,
(dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	2010
Fixed-rate long-term debt	$ 1,000	$ 950	$ 830	$ 300	$ 1,000	$ 7,449	$ 11,529	$ 12,826
Average interest rate	6.96 %	6.67 %	4.96 %	6.05 %	5.18 %	6.18 %	6.11 %	
Variable-rate long-term debt	-	-	-	-	-	$ 861	$ 861	$ 861
Average interest rate	-	-	-	-	-	0.53 %	0.53 %	
Debt to affiliated trust[a]	-	-	-	-	-	$ 309	$ 309	$ 315
Interest rate	-	-	-	-	-	7.10 %	7.10 %	
Interest rate forward contracts[b]	$ 550	$ 400	$ 100	-	-	-	$ 1,050	$ (35)
Average pay rate	4.19 %	4.23 %	4.37 %	-	-	-	4.22 %	
Average receive rate	[c]	[c]	[c]	-	-	-	[c]	

[a] Florida Progress Funding Corporation - Junior Subordinated Deferrable Interest Notes.

[b] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

[c] Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million notional at PEC and $200 million notional at PEF.

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, 2011 and December 31, 2010, the fair value of these funds was $1.647 billion and $1.571 billion, respectively, including $1.088 billion and $1.017 billion, respectively, for PEC and $559 million and $554 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 14 for further information on the trust fund securities.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

CVOs are recorded at fair value, and gains and losses from changes in fair value are recognized in earnings. The 18.5 million outstanding CVOs not held by Progress Energy at December 31, 2011, had a fair value of $14 million. The 98.6 million CVOs outstanding at December 31, 2010, had a fair value of $15 million. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analyses performed on the CVOs use observable prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A hypothetical 10 percent increase in the December 31, 2011 market price would result in a $1 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. At December 31, 2011, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

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

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, 2011 and 2010, about PEC's interest rate risk-sensitive instruments:

December 31, 2011 (dollars in millions)	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value December 31, 2011
Fixed-rate long-term debt	**$ 500**	**$ 405**	**$ -**	**$ 700**	**$ -**	**$ 1,974**	**$ 3,579**	**$ 4,102**
Average interest rate	**6.50 %**	**5.14 %**	**-**	**5.21 %**	**-**	**5.18 %**	**5.36 %**	
Variable-rate long-term debt	**-**	**-**	**-**	**-**	**-**	**$ 620**	**$ 620**	**$ 620**
Average interest rate	**-**	**-**	**-**	**-**	**-**	**0.20 %**	**0.20 %**	
Interest rate forward contracts[a]	**$ 200**	**$ 50**	**-**	**-**	**-**	**-**	**$ 250**	**$ (46)**
Average pay rate	**4.27 %**	**4.43 %**	**-**	**-**	**-**	**-**	**4.30 %**	
Average receive rate	**[b]**	**[b]**		**-**	**-**	**-**	**[b]**	

[a] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

[b] Rate is 3-month LIBOR, which was 0.58% at December 31, 2011.

At December 31, 2011, PEC had $250 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2010 (dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value December 31, 2010
Fixed-rate long-term debt	$ -	$ 500	$ 405	$ -	$ 700	$ 1,474	$ 3,079	$ 3,413
Average interest rate	-	6.50 %	5.14 %	-	5.21 %	5.91 %	5.75 %	
Variable-rate long-term debt	-	-	-	-	-	$ 620	$ 620	$ 620
Average interest rate	-	-	-	-	-	0.54 %	0.54 %	
Interest rate forward contracts[a]	$ 100	$ 200	$ 50	-	-	-	$ 350	$ (8)
Average pay rate	4.31 %	4.27 %	4.43 %	-	-	-	4.30 %	
Average receive rate	[b]	[b]	[b]	-	-	-	[b]	

[a] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

[b] Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, PEC had $350 million notional 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 the 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. See "Commodity Price Risk" discussion under Progress Energy mentioned previously and Note 18 for additional information with regard to PEC's commodity contracts and use of derivative financial instruments.

PEF

PEF has certain market risks inherent in its financial instruments, which arise from transactions entered into in the normal course of business. PEF's primary exposures are changes in interest rates with respect to long-term debt and commercial paper, fluctuations in the return on marketable securities with respect to its 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, 2011 and 2010, about PEF's interest rate risk-sensitive instruments:

December 31, 2011								**Fair Value December 31,**
(dollars in millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**2011**
Fixed-rate long-term debt	**$ -**	**$ 425**	**$ -**	**$ 300**	**$ -**	**$ 3,525**	**$ 4,250**	**$ 5,193**
Average interest rate	**-**	**4.80 %**	**-**	**5.10 %**	**-**	**5.74 %**	**5.60 %**	
Variable-rate long-term debt	**-**	**-**	**-**	**-**	**-**	**$ 241**	**$ 241**	**$ 241**
Average interest rate	**-**	**-**	**-**	**-**	**-**	**0.57 %**	**0.57 %**	
Interest rate forward contracts[a]	**-**	**$ 50**	**$ -**	**-**	**-**	**-**	**$ 50**	**$ (9)**
Average pay rate	**-**	**4.30 %**	**-**	**-**	**-**	**-**	**4.30 %**	
Average receive rate		**[b]**		**-**	**-**	**-**	**[b]**	

[a] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

[b] Rate is 3-month LIBOR, which was 0.58% at December 31, 2011.

At December 31, 2011, PEF had $50 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

December 31, 2010								Fair Value December 31,
(dollars in millions)	2011	2012	2013	2014	2015	Thereafter	Total	2010
Fixed-rate long-term debt	$ 300	$ -	$ 425	$ -	$ 300	$ 3,225	$ 4,250	$ 4,730
Average interest rate	6.65 %	-	4.80 %	-	5.10 %	5.99 %	5.85 %	
Variable-rate long-term debt	-	-	-	-	-	$ 241	$ 241	$ 241
Average interest rate	-	-	-	-	-	0.52 %	0.52 %	
Interest rate forward contracts[a]	$ 150	-	$ 50	-	-	-	$ 200	$ (7)
Average pay rate	4.18 %	-	4.30 %	-	-	-	4.21 %	
Average receive rate	[b]	-	- [b]	-	-	-	[b]	

[a] Notional amounts of 10-year forward starting swaps are categorized by mandatory cash settlement date.

[b] Rate is 3-month LIBOR, which was 0.30% at December 31, 2010.

At December 31, 2010, PEF had $200 million notional of open forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

COMMODITY PRICE RISK

PEF is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. PEF's exposure to these fluctuations is significantly limited by its cost-based regulation. The FPSC allows PEF to recover

certain fuel and purchased power costs to the extent the FPSC determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. See "Commodity Price Risk" discussion under Progress Energy mentioned previously and Note 18 for additional information with regard to PEF's commodity contracts and use of derivative financial instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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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 through 3, 5 through 8, 10 through 15, 17 through 19, 21, 22, and 24
PEF	1 through 3, 5 through 8, 10 through 15, 17 through 19, 21, 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 subsidiaries (the "Company") as of December 31, 2011 and 2010, 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, 2011. 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 subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on the criteria established in *Internal Control–Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data) Years ended December 31	2011	2010	2009
Operating revenues	**$ 8,907**	$ 10,190	$ 9,885
Operating expenses			
Fuel used in electric generation	**2,893**	3,300	3,752
Purchased power	**1,093**	1,279	911
Operation and maintenance	**2,036**	2,027	1,894
Depreciation, amortization and accretion	**701**	920	986
Taxes other than on income	**562**	580	557
Other	**34**	30	13
Total operating expenses	**7,319**	8,136	8,113
Operating income	**1,588**	2,054	1,772
Other income (expense)			
Interest income	**2**	7	14
Allowance for equity funds used during construction	**103**	92	124
Other, net	**(58)**	-	6
Total other income, net	**47**	99	144
Interest charges			
Interest charges	**760**	779	718
Allowance for borrowed funds used during construction	**(35)**	(32)	(39)
Total interest charges, net	**725**	747	679
Income from continuing operations before income tax	**910**	1,406	1,237
Income tax expense	**323**	539	397
Income from continuing operations	**587**	867	840
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income	**582**	863	761
Net income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Net income attributable to controlling interests	**$ 575**	$ 856	$ 757
Average common shares outstanding – basic	**296**	291	279
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	**$ 1.96**	$ 2.96	$ 2.99
Discontinued operations attributable to controlling interests, net of tax	**(0.02)**	(0.01)	(0.28)
Net income attributable to controlling interests	**$ 1.94**	$ 2.95	$ 2.71
Dividends declared per common share	**$ 2.119**	$ 2.480	$ 2.480
Amounts attributable to controlling interests			
Income from continuing operations, net of tax	**$ 580**	$ 860	$ 836
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income attributable to controlling interests	**$ 575**	$ 856	$ 757

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

PROGRESS ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(in millions)	December 31, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	$ 31,065	$ 29,708
Accumulated depreciation	(12,001)	(11,567)
Utility plant in service, net	19,064	18,141
Other utility plant, net	217	220
Construction work in progress	2,449	2,205
Nuclear fuel, net of amortization	767	674
Total utility plant, net	22,497	21,240
Current assets		
Cash and cash equivalents	230	611
Receivables, net	889	1,033
Inventory	1,438	1,226
Regulatory assets	275	176
Derivative collateral posted	147	164
Deferred tax assets	371	156
Prepayments and other current assets	133	110
Total current assets	3,483	3,476
Deferred debits and other assets		
Regulatory assets	3,025	2,374
Nuclear decommissioning trust funds	1,647	1,571
Miscellaneous other property and investments	407	413
Goodwill	3,655	3,655
Other assets and deferred debits	345	325
Total deferred debits and other assets	9,079	8,338
Total assets	$ 35,059	$ 33,054
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 295 million and 293 million shares issued and outstanding, respectively	$ 7,434	$ 7,343
Accumulated other comprehensive loss	(165)	(125)
Retained earnings	2,752	2,805
Total common stock equity	10,021	10,023
Noncontrolling interests	4	4
Total equity	10,025	10,027
Preferred stock of subsidiaries	93	93
Long-term debt, affiliate	273	273
Long-term debt, net	11,718	11,864
Total capitalization	22,109	22,257
Current liabilities		
Current portion of long-term debt	950	505
Short-term debt	671	-
Accounts payable	909	994
Interest accrued	200	216
Dividends declared	78	184
Customer deposits	340	324
Derivative liabilities	436	259
Accrued compensation and other benefits	195	175
Other current liabilities	306	298
Total current liabilities	4,085	2,955
Deferred credits and other liabilities		
Noncurrent income tax liabilities	2,355	1,696
Accumulated deferred investment tax credits	103	110
Regulatory liabilities	2,700	2,635
Asset retirement obligations	1,265	1,200
Accrued pension and other benefits	1,625	1,514
Derivative liabilities	352	278
Other liabilities and deferred credits	465	409
Total deferred credits and other liabilities	8,865	7,842
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$ 35,059	$ 33,054

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)

Years ended December 31	2011	2010	2009
Operating activities			
Net income	$ 582	$ 863	$ 761
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	870	1,083	1,135
Deferred income taxes and investment tax credits, net	353	478	220
Deferred fuel (credit) cost	(102)	(2)	290
Allowance for equity funds used during construction	(103)	(92)	(124)
Amount to be refunded to customers (Note 8C)	288	-	-
Pension, postretirement and other employee benefits	180	198	135
Other adjustments to net income	50	49	136
Cash provided (used) by changes in operating assets and liabilities			
Receivables	175	(200)	26
Inventory	(210)	98	(99)
Derivative collateral posted	20	(23)	200
Other assets	(23)	(1)	14
Income taxes, net	51	90	(14)
Accounts payable	(69)	125	(26)
Accrued pension and other benefits	(396)	(164)	(285)
Other liabilities	(51)	35	(98)
Net cash provided by operating activities	1,615	2,537	2,271
Investing activities			
Gross property additions	(2,066)	(2,221)	(2,295)
Nuclear fuel additions	(226)	(221)	(200)
Purchases of available-for-sale securities and other investments	(5,017)	(7,009)	(2,350)
Proceeds from available-for-sale securities and other investments	4,970	6,990	2,314
Insurance proceeds	79	64	-
Other investing activities	48	(3)	(1)
Net cash used by investing activities	(2,212)	(2,400)	(2,532)
Financing activities			
Issuance of common stock, net	53	434	623
Dividends paid on common stock	(734)	(717)	(693)
Payments of short-term debt with original maturities greater than 90 days	-	-	(629)
Net increase (decrease) in short-term debt	667	(140)	(381)
Proceeds from issuance of long-term debt, net	1,286	591	2,278
Retirement of long-term debt	(1,000)	(400)	(400)
Other financing activities	(56)	(19)	8
Net cash provided (used) by financing activities	216	(251)	806
Net (decrease) increase in cash and cash equivalents	(381)	(114)	545
Cash and cash equivalents at beginning of year	611	725	180
Cash and cash equivalents at end of year	$ 230	$ 611	$ 725
Supplemental disclosures			
Cash paid for interest less amount capitalized, net	$ 793	$ 709	$ 701
Cash (received) paid for income taxes	(78)	(56)	87
Significant noncash transactions			
Accrued property additions	334	313	252
Asset retirement obligation additions and estimate revisions	(4)	(36)	(384)

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, 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		-	-	-	-	1	1
Balance, December 31, 2009	**281**	**6,873**	**(12)**	**(87)**	**2,675**	**6**	**9,455**
Cumulative effect of change in accounting principle		-	-	-	-	(2)	(2)
Net income[a]		-	-	-	856	3	859
Other comprehensive loss		-	-	(38)	-	-	(38)
Issuance of shares	12	434	-	-	-	-	434
Allocation of ESOP shares		9	12	-	-	-	21
Stock-based compensation expense		27	-	-	-	-	27
Dividends ($2.480 per share)		-	-	-	(726)	-	(726)
Distributions to noncontrolling interests		-	-	-	-	(2)	(2)
Other		-	-	-	-	(1)	(1)
Balance, December 31, 2010	**293**	**7,343**	**-**	**(125)**	**2,805**	**4**	**10,027**
Net income[a]		**-**	**-**	**-**	**575**	**3**	**578**
Other comprehensive loss		**-**	**-**	**(40)**	**-**	**-**	**(40)**
Issuance of shares	**2**	**53**	**-**	**-**	**-**	**-**	**53**
Stock-based compensation expense		**38**	**-**	**-**	**-**	**-**	**38**
Dividends ($2.119 per share)		**-**	**-**	**-**	**(628)**	**-**	**(628)**
Distributions to noncontrolling interests		**-**	**-**	**-**	**-**	**(3)**	**(3)**
Balance, December 31, 2011	**295**	**$ 7,434**	**$ -**	**$ (165)**	**$ 2,752**	**$ 4**	**$ 10,025**

[a] For the year ended December 31, 2011, consolidated net income of $582 million includes $4 million attributable to preferred shareholders of subsidiaries. For the year ended December 31, 2010, consolidated net income of $863 million includes $4 million attributable to preferred shareholders of subsidiaries. For the year ended December 31, 2009, consolidated net income of $761 million includes $4 million attributable to preferred shareholders of subsidiaries. Income attributable to preferred shareholders of subsidiaries 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,	2011	2010	2009
Net income	**$ 582**	$ 863	$ 761
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $5, $4 and $4)	**8**	6	6
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $3, $2 and $3)	**5**	3	4
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $56, $22 and $(10))	**(87)**	(34)	16
Net unrecognized items for pension and other postretirement benefits (net of tax (expense) benefit of $(24), $8 and $(1))	**34**	(13)	2
Other (net of tax benefit of $-)	**-**	-	1
Other comprehensive (loss) income	**(40)**	(38)	29
Comprehensive income	**542**	825	790
Comprehensive income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Comprehensive income attributable to controlling interests	**$ 535**	$ 818	$ 786

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 subsidiaries ("PEC") as of December 31, 2011 and 2010, 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, 2011. 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 PEC'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 Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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 28, 2012

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

CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	2011	2010	2009
Operating revenues	**$ 4,528**	$ 4,922	$ 4,627
Operating expenses			
Fuel used in electric generation	**1,387**	1,686	1,680
Purchased power	**315**	302	229
Operation and maintenance	**1,182**	1,158	1,072
Depreciation, amortization and accretion	**514**	479	470
Taxes other than on income	**211**	218	210
Other	**34**	8	-
Total operating expenses	**3,643**	3,851	3,661
Operating income	**885**	1,071	966
Other income (expense)			
Interest income	**1**	3	5
Allowance for equity funds used during construction	**71**	64	33
Other, net	**(1)**	-	(18)
Total other income, net	**71**	67	20
Interest charges			
Interest charges	**205**	205	207
Allowance for borrowed funds used during construction	**(21)**	(19)	(12)
Total interest charges, net	**184**	186	195
Income before income tax	**772**	952	791
Income tax expense	**256**	350	277
Net income	**516**	602	514
Net loss attributable to noncontrolling interests, net of tax	**-**	1	2
Net income attributable to controlling interests	**516**	603	516
Preferred stock dividend requirement	**(3)**	(3)	(3)
Net income available to parent	**$ 513**	$ 600	$ 513

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, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	$ 17,439	$ 16,388
Accumulated depreciation	(7,567)	(7,324)
Utility plant in service, net	9,872	9,064
Other utility plant, net	181	184
Construction work in progress	1,294	1,233
Nuclear fuel, net of amortization	540	480
Total utility plant, net	11,887	10,961
Current assets		
Cash and cash equivalents	20	230
Receivables, net	492	519
Receivables from affiliated companies	13	44
Inventory	775	590
Deferred fuel cost	31	71
Income taxes receivable	8	90
Deferred tax assets	142	65
Prepayments and other current assets	68	47
Total current assets	1,549	1,656
Deferred debits and other assets		
Regulatory assets	1,310	987
Nuclear decommissioning trust funds	1,088	1,017
Miscellaneous other property and investments	188	183
Other assets and deferred debits	80	95
Total deferred debits and other assets	2,666	2,282
Total assets	$ 16,102	$ 14,899
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	$ 2,148	$ 2,130
Accumulated other comprehensive loss	(71)	(33)
Retained earnings	3,011	3,083
Total common stock equity	5,088	5,180
Preferred stock	59	59
Long-term debt, net	3,693	3,693
Total capitalization	8,840	8,932
Current liabilities		
Current portion of long-term debt	500	-
Short-term debt	188	-
Notes payable to affiliated companies	31	-
Accounts payable	527	534
Payables to affiliated companies	41	109
Interest accrued	77	74
Customer deposits	116	106
Derivative liabilities	130	53
Accrued compensation and other benefits	110	99
Other current liabilities	85	81
Total current liabilities	1,805	1,056
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,976	1,608
Accumulated deferred investment tax credits	98	104
Regulatory liabilities	1,543	1,461
Asset retirement obligations	896	849
Accrued pension and other benefits	687	723
Other liabilities and deferred credits	257	166
Total deferred credits and other liabilities	5,457	4,911
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$ 16,102	$ 14,899

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	2011	2010	2009
Operating activities			
Net income	$ 516	$ 602	$ 514
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	659	602	585
Deferred income taxes and investment tax credits, net	262	285	64
Deferred fuel cost	43	79	187
Allowance for equity funds used during construction	(71)	(64)	(33)
Pension, postretirement and other employee benefits	67	78	65
Other adjustments to net income	(50)	4	67
Cash provided (used) by changes in operating assets and liabilities			
Receivables	106	(76)	42
Receivables from affiliated companies	31	(11)	(4)
Inventory	(184)	85	(56)
Other assets	(16)	(24)	28
Income taxes, net	92	(54)	50
Accounts payable	(26)	51	(18)
Payables to affiliated companies	(68)	37	(10)
Accrued pension and other benefits	(247)	(95)	(181)
Other liabilities	23	19	(17)
Net cash provided by operating activities	1,137	1,518	1,283
Investing activities			
Gross property additions	(1,232)	(1,198)	(839)
Nuclear fuel additions	(211)	(183)	(122)
Purchases of available-for-sale securities and other investments	(571)	(489)	(696)
Proceeds from available-for-sale securities and other investments	515	437	642
Changes in advances to affiliated companies	2	202	(149)
Other investing activities	28	1	1
Net cash used by investing activities	(1,469)	(1,230)	(1,163)
Financing activities			
Dividends paid on preferred stock	(3)	(3)	(3)
Dividends paid to parent	(585)	(100)	(200)
Net increase (decrease) in short-term debt	185	-	(110)
Proceeds from issuance of long-term debt, net	495	-	595
Retirement of long-term debt	-	-	(400)
Changes in advances from affiliated companies	31	-	-
Contributions from parent	-	14	15
Other financing activities	(1)	(4)	-
Net cash provided (used) by financing activities	122	(93)	(103)
Net (decrease) increase in cash and cash equivalents	(210)	195	17
Cash and cash equivalents at beginning of year	230	35	18
Cash and cash equivalents at end of year	$ 20	$ 230	$ 35
Supplemental disclosures			
Cash paid for interest less amount capitalized, net	$ 199	$ 166	$ 171
Cash (received) paid for income taxes, net	(97)	108	144
Significant noncash transactions			
Accrued property additions	236	198	91
Asset retirement obligation additions and estimate revisions	(4)	1	(386)

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, 2008	**160**	**$ 2,083**	**$ (25)**	**$ (35)**	**$ 2,278**	**$ 4**	**$ 4,305**
Net income		-	-	-	516	(2)	514
Other comprehensive income		-	-	8	-	-	8
Allocation of ESOP shares		10	13	-	-	-	23
Stock-based compensation expense		15	-	-	-	-	15
Dividends paid to parent		-	-	-	(200)	-	(200)
Preferred stock dividends at stated rates		-	-	-	(3)	-	(3)
Tax dividend		-	-	-	(3)	-	(3)
Other		-	-	-	-	1	1
Balance, December 31, 2009	**160**	**2,108**	**(12)**	**(27)**	**2,588**	**3**	**4,660**
Cumulative effect of change in accounting principle		-	-	-	-	(2)	(2)
Net income		-	-	-	603	(1)	602
Other comprehensive loss		-	-	(6)	-	-	(6)
Allocation of ESOP shares		10	12	-	-	-	22
Stock-based compensation expense		12	-	-	-	-	12
Dividends paid to parent		-	-	-	(100)	-	(100)
Preferred stock dividends at stated rates		-	-	-	(3)	-	(3)
Tax dividend		-	-	-	(5)	-	(5)
Balance, December 31, 2010	**160**	**2,130**	**-**	**(33)**	**3,083**	**-**	**5,180**
Net income		**-**	**-**	**-**	**516**	**-**	**516**
Other comprehensive loss		**-**	**-**	**(38)**	**-**	**-**	**(38)**
Stock-based compensation expense		**18**	**-**	**-**	**-**	**-**	**18**
Dividends paid to parent		**-**	**-**	**-**	**(585)**	**-**	**(585)**
Preferred stock dividends at stated rates		**-**	**-**	**-**	**(3)**	**-**	**(3)**
Balance, December 31, 2011	**160**	**$ 2,148**	**$ -**	**$ (71)**	**$ 3,011**	**$ -**	**$ 5,088**

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

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31,	2011	2010	2009
Net income	**$ 516**	$ 602	$ 514
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $3, $3 and $2)	5	4	3
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $28, $6 and $(3))	(43)	(10)	5
Other comprehensive (loss) income	(38)	(6)	8
Comprehensive income	478	596	522
Comprehensive loss attributable to noncontrolling interests, net of tax	-	1	2
Comprehensive income attributable to controlling interests	**$ 478**	$ 597	$ 524

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS 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, 2011 and 2010, 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, 2011. 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 PEF'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 Florida Power Corporation d/b/a Progress Energy Florida, Inc. as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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 28, 2012

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

STATEMENTS of INCOME

(in millions) Years ended December 31	2011	2010	2009
Operating revenues	**$ 4,369**	$ 5,254	$ 5,251
Operating expenses			
Fuel used in electric generation	**1,506**	1,614	2,072
Purchased power	**778**	977	682
Operation and maintenance	**881**	912	839
Depreciation, amortization and accretion	**169**	426	502
Taxes other than on income	**350**	362	347
Other	**(13)**	4	7
Total operating expenses	**3,671**	4,295	4,449
Operating income	**698**	959	802
Other income (expense)			
Interest income	**1**	1	4
Allowance for equity funds used during construction	**32**	28	91
Other, net	**2**	(1)	5
Total other income, net	**35**	28	100
Interest charges			
Interest charges	**253**	271	258
Allowance for borrowed funds used during construction	**(14)**	(13)	(27)
Total interest charges, net	**239**	258	231
Income before income tax	**494**	729	671
Income tax expense	**180**	276	209
Net income	**314**	453	462
Preferred stock dividend requirement	**(2)**	(2)	(2)
Net income available to parent	**$ 312**	$ 451	$ 460

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, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant in service	$ 13,461	$ 13,155
Accumulated depreciation	(4,356)	(4,168)
Utility plant in service, net	9,105	8,987
Held for future use	36	36
Construction work in progress	1,155	972
Nuclear fuel, net of amortization	227	194
Total utility plant, net	10,523	10,189
Current assets		
Cash and cash equivalents	16	249
Receivables, net	372	496
Receivables from affiliated companies	19	11
Inventory	663	636
Regulatory assets	244	105
Derivative collateral posted	123	140
Deferred tax assets	138	77
Prepayments and other current assets	39	29
Total current assets	1,614	1,743
Deferred debits and other assets		
Regulatory assets	1,602	1,387
Nuclear decommissioning trust funds	559	554
Miscellaneous other property and investments	42	43
Other assets and deferred debits	144	140
Total deferred debits and other assets	2,347	2,124
Total assets	$ 14,484	$ 14,056
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	$ 1,757	$ 1,750
Accumulated other comprehensive loss	(27)	(4)
Retained earnings	2,945	3,144
Total common stock equity	4,675	4,890
Preferred stock	34	34
Long-term debt, net	4,482	4,182
Total capitalization	9,191	9,106
Current liabilities		
Current portion of long-term debt	-	300
Short-term debt	233	-
Notes payable to affiliated companies	8	9
Accounts payable	358	439
Payables to affiliated companies	25	60
Interest accrued	54	83
Customer deposits	224	218
Derivative liabilities	268	188
Accrued compensation and other benefits	53	47
Other current liabilities	112	121
Total current liabilities	1,335	1,465
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,405	1,065
Regulatory liabilities	1,071	1,084
Asset retirement obligations	369	351
Accrued pension and other benefits	598	522
Capital lease obligations	189	199
Derivative liabilities	231	190
Other liabilities and deferred credits	95	74
Total deferred credits and other liabilities	3,958	3,485
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$ 14,484	$ 14,056

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	2011	2010	2009
Operating activities			
Net income	$ 314	$ 453	$ 462
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	174	446	527
Deferred income taxes and investment tax credits, net	234	324	64
Deferred fuel (credit) cost	(145)	(81)	103
Allowance for equity funds used during construction	(32)	(28)	(91)
Amount to be refunded to customers (Note 8C)	288	-	-
Pension, postretirement and other employee benefits	62	79	28
Other adjustments to net income	26	44	88
Cash provided (used) by changes in operating assets and liabilities			
Receivables	78	(110)	(15)
Receivables from affiliated companies	(8)	(3)	7
Inventory	(26)	13	(43)
Derivative collateral posted	19	(6)	190
Other assets	(4)	(17)	15
Income taxes, net	51	50	(75)
Accounts payable	(46)	79	(11)
Payables to affiliated companies	(35)	(2)	7
Accrued pension and other benefits	(137)	(61)	(83)
Other liabilities	(48)	24	(36)
Net cash provided by operating activities	765	1,204	1,137
Investing activities			
Gross property additions	(816)	(1,014)	(1,449)
Nuclear fuel additions	(15)	(38)	(78)
Purchases of available-for-sale securities and other investments	(4,435)	(6,386)	(1,540)
Proceeds from available-for-sale securities and other investments	4,438	6,390	1,545
Insurance proceeds	76	64	-
Other investing activities	45	(3)	(6)
Net cash used by investing activities	(707)	(987)	(1,528)
Financing activities			
Dividends paid on preferred stock	(2)	(2)	(2)
Dividends paid to parent	(510)	(50)	-
Net increase (decrease) in short-term debt	233	-	(371)
Proceeds from issuance of long-term debt, net	296	591	-
Retirement of long-term debt	(300)	(300)	-
Changes in advances from affiliated companies	(1)	(212)	149
Contributions from parent	-	-	620
Other financing activities	(7)	(12)	(7)
Net cash (used) provided by financing activities	(291)	15	389
Net (decrease) increase in cash and cash equivalents	(233)	232	(2)
Cash and cash equivalents at beginning of year	249	17	19
Cash and cash equivalents at end of year	$ 16	$ 249	$ 17
Supplemental disclosures			
Cash paid for interest less amount capitalized, net	$ 287	$ 241	$ 228
Cash (received) paid for income taxes	(83)	(98)	184
Significant noncash transactions			
Accrued property additions	93	111	156

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

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 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 dividend		-	-	(1)	(1)
Balance, December 31, 2009	**100**	**1,744**	**3**	**2,743**	**4,490**
Net income		-	-	453	453
Other comprehensive loss		-	(7)	-	(7)
Stock-based compensation expense		6	-	-	6
Dividends paid to parent		-	-	(50)	(50)
Preferred stock dividends at stated rates		-	-	(2)	(2)
Balance, December 31, 2010	**100**	**1,750**	**(4)**	**3,144**	**4,890**
Net income		**-**	**-**	**314**	**314**
Other comprehensive loss		**-**	**(23)**	**-**	**(23)**
Stock-based compensation expense		**7**	**-**	**-**	**7**
Dividends paid to parent		**-**	**-**	**(510)**	**(510)**
Preferred stock dividends at stated rates		**-**	**-**	**(2)**	**(2)**
Tax dividend		**-**	**-**	**(1)**	**(1)**
Balance, December 31, 2011	**100**	**$ 1,757**	**$ (27)**	**$ 2,945**	**$ 4,675**

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

STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31,	2011	2010	2009
Net income	**$ 314**	$ 453	$ 462
Other comprehensive (loss) income			
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $15, $4 and $(2))	**(23)**	(7)	4
Other comprehensive (loss) income	**(23)**	(7)	4
Comprehensive income	**$ 291**	$ 446	$ 466

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

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

PROGRESS ENERGY

The Parent is a holding company headquartered in Raleigh, N.C., subject to regulation by the Federal Energy Regulatory Commission (FERC).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 20 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 jurisdiction 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 jurisdiction 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. Intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in noncontrolling interests 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 13 for more information about our investments.

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 2010 and 2009 have been reclassified to conform to the 2011 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. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. The variable interest holder who has both of the following has the controlling financial interest and is the primary beneficiary: (1) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (2) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. In performing our 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.

PROGRESS ENERGY

Progress Energy, through its subsidiary PEC, is the primary beneficiary of, and consolidates an entity that qualifies for rehabilitation tax credits under Section 47 of the Internal Revenue Code. Our variable interests are debt and equity investments in the VIE. There were no changes to our assessment of the primary beneficiary for this VIE during 2009 through 2011. No financial or other support has been provided to the VIE during the periods presented.

The following table sets forth the carrying amount and classification of our investment in the VIE as reflected in the Consolidated Balance Sheets at December 31:

(in millions)	2011	2010
Miscellaneous other property and investments	$ 12	$ 12
Cash and cash equivalents	1	-
Prepayments and other current assets	-	1
Accounts payable	-	5

The assets of the VIE are collateral for, and can only be used to settle, its obligations. The creditors of the VIE do not have recourse to our general credit or the general credit of PEC, and there are no other arrangements that could expose us to losses.

Progress Energy, through its subsidiary PEC, is the primary beneficiary of two VIEs that were established to lease buildings to PEC under capital lease agreements. Our maximum exposure to loss from these leases is a $7.5 million mandatory fixed price purchase option for one of the buildings. Total lease payments to these counterparties under the lease agreements were $2 million annually in 2011, 2010 and 2009. We have requested the necessary information to consolidate these entities; both entities from which the necessary financial information was requested declined to provide the information to us, and, accordingly, we have applied the information scope exception provided by GAAP to the entities. We believe the effect of consolidating the entities would have an insignificant

impact on our common stock equity, net earnings or cash flows. However, because we have not received any financial information from the counterparties, the impact cannot be determined at this time.

PEC

See discussion of PEC's variable interests in VIEs within the Progress Energy section.

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. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns and customer mix. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

Periodically, we are permitted to start charging customers for proposed rate increases prior to receiving final approval from our regulatory authorities. Such amounts charged are subject to refund upon issuance of the final rate order. In addition, we may be required to refund amounts to customers for previously recognized revenues, through approved orders or settlement agreements, which are not related to proposed rate increases. We recognize revenue subject to refund when it is earned, and separately establish a reserve for amounts that could be refunded when it is probable that revenue will be refunded to customers. See Note 8C for discussion of revenue to be refunded in connection with the 2012 settlement agreement.

FUEL COST DEFERRALS

Fuel expense includes fuel costs and other recoveries that were previously 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)	2011	2010	2009
Progress Energy	**$ 315**	$ 345	$ 333
PEC	**110**	119	108
PEF	**205**	226	225

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with FERC regulations. 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. 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 generally occur every two years. Maintenance activities under long-term service agreements with third parties are capitalized or expensed as appropriate as if the Utilities had performed the activities. Generally, the cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. For generating facilities to be retired or abandoned significantly before the end of their useful lives, the net carrying value is reclassified from plant in service, net to other utility plant, net when it becomes probable they will be retired or abandoned. When such facilities are removed from service, the remaining net carrying value is then reclassified to regulatory assets in accordance with the expected ratemaking treatment. 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. Both the debt and equity components of AFUDC are noncash amounts within the Consolidated Statements of Income. The equity funds component of AFUDC is credited to other income, and the borrowed funds component is credited to interest charges.

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Consolidated 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 5A). 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 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method and included within fuel used in electric generation in the Consolidated Statements of Income.

FEDERAL GRANT

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency (EE) and renewable energy. On April 28, 2010, we accepted a grant from the United States

Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our smart grid initiatives. PEC and PEF each will receive up to $100 million over a three-year period as project work progresses. The DOE will provide reimbursement for 50 percent of allowable project costs, as incurred, up to the DOE's maximum obligation of $200 million. Projects funded by the grant must be completed by April 2013.

In accounting for the federal grant, we have elected to reduce the cost basis of select smart grid projects. As the select capital projects are placed into service, this will reduce depreciation expense over the life of the assets. Reimbursements by the DOE are deferred as a short-term or long-term liability on the Consolidated Balance Sheets based on their expected date of application to the select projects. Reimbursements related to capital projects are included in other investing activities in the Statement of Cash Flows when cash is received.

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. AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities in order to reflect the ratemaking treatment of the related costs.

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.

RECEIVABLES, NET

We record accounts receivable at net realizable value. This value includes an allowance for estimated uncollectible accounts to reflect any loss anticipated on the accounts receivable balances. The allowance for uncollectible accounts reflects our estimate of probable losses inherent in the accounts receivable, unbilled revenue, and other receivables balances. We calculate this allowance based on our history of write-offs, level of past due accounts, prior rate of recovery experience and relationships with and economic status of our customers.

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 8A). Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Additionally, management continually assesses whether any regulatory liabilities have been incurred. 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. We perform our annual goodwill impairment test as of October 31 each year and perform an interim test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. 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 8A).

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 (primarily fuel-related) receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory

liabilities and assets, respectively, until the contracts are settled. Cash flows from derivative instruments are generally included in cash provided by operating activities on the Statements of Cash Flows. See Note 18 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. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. With the exception of legal fees that are incremental direct costs of an environmental remediation effort, 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, including legal fees, 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. MERGER AGREEMENT

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the Merger Agreement). Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction (the Merger) and become a wholly owned subsidiary of Duke Energy. The Merger Agreement originally had a termination date of January 8, 2012, which has been extended by the parties to July 8, 2012.

Under the terms of the Merger Agreement, each share of Progress Energy common stock will be canceled and converted into the right to receive 2.6125 shares of Duke Energy common stock. Each outstanding option to acquire, and each outstanding equity award relating to, one share of Progress Energy common stock will be converted into an option to acquire, or an equity award relating to, 2.6125 shares of Duke Energy common stock. The board of directors of Duke Energy approved a reverse stock split, at a ratio of 1-for-3, subject to completion of the Merger. Accordingly, the adjusted exchange ratio is expected to be 0.87083 of a share of Duke Energy common stock, options and equity awards for each Progress Energy common share, option and equity award.

The combined company, to be called Duke Energy, will have an 18-member board of directors. The board will be comprised of, subject to their ability and willingness to serve, all 11 current directors of Duke Energy and seven current directors of Progress Energy. At the time of the Merger, William D. Johnson, Chairman, President and CEO of Progress Energy, will be President and CEO of Duke Energy, and James E. Rogers, Chairman, President and CEO of Duke Energy, will be the Executive Chairman of the board of directors of Duke Energy, subject to their ability and willingness to serve.

Consummation of the Merger is subject to customary conditions, including, among others things, approval by the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approvals, to the extent required, from the FERC, the Federal Communications Commission, the NRC, the NCUC, the Kentucky Public Service Commission and the SCPSC. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required. The status of these matters is as follows, and we cannot predict the outcome of pending approvals:

Shareholder Approval

- On August 23, 2011, the Merger was approved by the shareholders of Progress Energy and Duke Energy.

Federal Regulatory Approvals

- On March 28, 2011, Progress Energy and Duke Energy submitted their Hart-Scott-Rodino filing with the U.S. Department of Justice (DOJ) for review under U.S. antitrust laws. The 30-day waiting period required by the Hart-Scott-Rodino Act expired without Progress Energy or Duke Energy having received requests for additional information. Progress Energy and Duke Energy have met their obligations under the Hart-Scott-Rodino Act. However, the period in which Progress Energy and Duke Energy may close the Merger consistent with their Hart-Scott-Rodino obligations will expire on April 26, 2012. Because the Merger is not expected to close on or before April 26, 2012, Progress Energy and Duke Energy intend to make new filings under the Hart-Scott-Rodino Act in order to be able to close the Merger after such date and continue to meet their obligations under the Hart-Scott-Rodino Act.
- On January 5, 2012, the Federal Communications Commission extended its approval of the Assignment of Authorization filings to transfer control of certain licenses. The extended approval expires on July 12, 2012.
- On September 30, 2011, the FERC, which assesses market power-related issues, conditionally approved the merger application filed by Progress Energy and Duke Energy. The approval is subject to the FERC's acceptance of market power mitigation measures to address the FERC's finding that the combined company could have an adverse effect on competition in the North Carolina and South Carolina wholesale power markets. Progress Energy and Duke Energy filed a market power mitigation plan with the FERC on October 17, 2011 that proposed a "virtual divestiture" under which power up to a certain amount would have been offered into the wholesale market rather than the sale or divestiture of physical assets. A virtual divestiture is one option the FERC indicated could be used to mitigate its market power concerns. On December 14, 2011, the FERC affirmed its conditional approval of the merger, but the FERC rejected the proposed market power mitigation plan. On February 22, 2012, Progress Energy and Duke Energy filed a notification with the NCUC of their intention to file a second market power mitigation plan with the FERC. The revised mitigation plan consists of two phases. Phase 1 is an interim mitigation that consists of a virtual divestiture whereby the companies propose a three-year plan to sell capacity and firm energy during the summer (June – August) and winter (December – February) to new market participants. Together, the companies would sell 800 MWs during summer off-peak hours, 475 MWs during summer peak hours, 225 MWs during winter off-peak hours, and 25 MWs during winter peak hours. The companies expect to secure contracts with potential buyers prior to filing the mitigation plan with the FERC. Phase 2 is a permanent mitigation that consists of constructing up to eight transmission projects in the combined service territories, which will expand the capability to import wholesale power into the Carolinas. The construction, preliminarily estimated to cost $75 million to $150 million, would begin after the Merger closes and take approximately three years to complete. The companies will be working with the North Carolina Public Staff and the South Carolina Office of Regulatory Staff (ORS) on appropriate state ratemaking treatment associated with the measures in the revised market mitigation plan and other merger-related issues. Final agreement to the proposed mitigation efforts will be subject to resolution of the state

ratemaking issues. The NCUC has up to 30 days to review the revised mitigation plan before it is filed with the FERC.

- On April 4, 2011, Progress Energy and Duke Energy made two additional filings with the FERC. The first filing is a Joint Dispatch Agreement, pursuant to which PEC and Duke Energy Carolinas will agree to jointly dispatch their generation facilities in order to achieve certain of the operating efficiencies expected to result from the Merger. The second filing is a joint open access transmission tariff (OATT) pursuant to which PEC and Duke Energy Carolinas will agree to provide transmission service over their transmission facilities under a single transmission rate. On December 14, 2011, in conjunction with the aforementioned decision on the proposed market power mitigation plan, the FERC dismissed these related filings as not ripe for decision. As allowed under the FERC's December 14, 2011 order, Progress Energy and Duke Energy intend to refile the Joint Dispatch Agreement and OATT upon filing of the second market power mitigation plan with the FERC.
- On December 2, 2011, the NRC approved the filing requesting an indirect transfer of control of licenses for Progress Energy's nuclear facilities to include Duke Energy as the ultimate parent corporation on these licenses.

State Regulatory Approvals

- On April 4, 2011, Progress Energy and Duke Energy filed a merger approval application and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas with the NCUC. On September 2, 2011, the North Carolina Public Staff filed a settlement agreement with the NCUC. On September 6, 2011, Progress Energy and Duke Energy signed a settlement with the ORS, a party to the North Carolina proceedings to resolve the ORS's issues in the North Carolina proceeding. Under the settlement agreement with the North Carolina Public Staff, Progress Energy and Duke Energy will provide $650 million in system fuel cost savings for customers in North Carolina and South Carolina over the five years following the close of the Merger, maintain their current level of community support in North Carolina for the next four years, and provide $15 million for low-income energy assistance and workforce development in North Carolina. The settlement agreement also provides that direct merger-related expenses will not be recovered from customers; however, PEC may request recovery of costs incurred to create operational savings. The NCUC held hearings regarding the application on September 20-22, 2011. On November 23, 2011, Progress Energy and Duke Energy filed proposed orders and briefs with the NCUC. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.
- On April 25, 2011, Progress Energy and Duke Energy filed an application for approval of the merger of PEC and Duke Energy Carolinas and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas with the SCPSC. On September 13, 2011, Progress Energy and Duke Energy withdrew the application of the merger of PEC and Duke Energy Carolinas, as the merger of these entities is not likely to occur for several years after the close of the Merger. The SCPSC held hearings regarding the application for approval of the Joint Dispatch Agreement on December 12, 2011. During the hearing, PEC, Duke Energy Carolinas and the ORS agreed to terminate the settlement agreement, which resolved the ORS's issues in the NCUC merger proceeding, and replaced it with a commitment by PEC and Duke Energy Carolinas to provide PEC's and Duke Energy Carolinas' retail customers in South Carolina pro rata benefits equivalent to those approved by the NCUC in its order ruling upon PEC's and Duke Energy Carolinas' merger application. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.
- On October 28, 2011, the Kentucky Public Service Commission approved Progress Energy's and Duke Energy's merger-related settlement agreement with the Attorney General of the Commonwealth of Kentucky.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to consummation of the Merger. Among other restrictions, the Merger Agreement limits our total capital spending, limits the extent to which we can obtain financing through long-term debt and equity, and we may not, without the prior approval of Duke Energy, increase our quarterly common stock dividend of $0.62 per share. In the fourth quarter of 2011, our board of directors declared a partial dividend payment to Progress Energy shareholders to align Progress Energy's dividend payment schedule with that of Duke Energy such that following

the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy dividend schedule.

Certain substantial changes in ownership of Progress Energy, including the Merger, can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards (See Note 15).

The Merger Agreement contains certain termination rights for both companies; under specified circumstances we may be required to pay Duke Energy $400 million and Duke Energy may be required to pay us $675 million. In addition, under specified circumstances each party may be required to reimburse the other party for up to $30 million of merger-related expenses.

Certain Progress Energy shareholders filed class action lawsuits in the state and federal courts in North Carolina against Progress Energy and each of the members of Progress Energy's board of directors, which have been subsequently settled (See Note 22D).

In connection with the Merger, we established an employee retention plan for certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger and the employees' continued employment through a specified time period following the Merger. These payments will be recorded as compensation expense following consummation of the Merger. We estimate the costs of the retention plan to be $14 million.

In connection with the Merger, we announced plans to offer a voluntary severance plan (VSP) to certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger. The window for eligible employees to request a voluntary end to their employment under the VSP opened on November 7, 2011, and ended on November 30, 2011. Approximately 650 employees requested and were approved for separation under the VSP in December 2011. The cost of the VSP is estimated to be between $90 million to $100 million, including $65 million to $70 million and $25 million to $30 million related to PEC and PEF, respectively. If the employee is not required to work for a significant period after the consummation of the Merger, the costs of any benefits paid under the VSP will be measured and recorded upon consummation of the Merger. If a significant retention period exists, the costs of benefits equal to what would be paid under our existing severance plan will be measured and recorded upon consummation of the Merger. Any additional benefits paid under the VSP will be recorded ratably over the remaining service periods of the affected employees.

In addition, we evaluated our business needs for office space after the Merger and formulated an exit plan to vacate one of our corporate headquarters buildings. Under the plan, we will gradually vacate the premises beginning in the fourth quarter of 2011 through January 1, 2013. In December 2011, we executed an agreement with a third party to sublease the building until 2035. The estimated exit cost liability associated with this exit plan is $17 million for us, of which $12 million of expense is attributable to PEC and $5 million to PEF. The exit cost liability will be recognized proportionately as we vacate the premises. During the fourth quarter of 2011, we recorded exit cost liabilities of $5 million for us, of which $3 million of expense is attributable to PEC and $2 million to PEF. These costs are included in merger and integration-related costs.

In connection with the Merger, we incurred merger and integration-related costs of $46 million, net of tax, including $25 million, net of tax, and $21 million, net of tax, at PEC and PEF, respectively, for the year ended December 31, 2011. These costs are included in operations and maintenance (O&M) expense in our Consolidated Statements of Income.

3. NEW ACCOUNTING STANDARDS

FAIR VALUE MEASUREMENT AND DISCLOSURES

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends Accounting Standards Codification (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 was effective for us on January 1,

2010, with certain disclosures effective January 1, 2011. The adoption of ASU 2010-06 resulted in additional disclosures in the notes to the financial statements but did not have an impact on our or the Utilities' financial position, results of operations or cash flows.

In May 2011, the FASB issued ASU 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which amends ASC 820 to develop a single, converged fair value framework between GAAP and International Financial Reporting Standards (IFRS). ASU 2011-04 is effective prospectively for us on January 1, 2012. The adoption of ASU 2011-04 will result in changes in certain fair value measurement principles, as well as additional disclosure in the notes to the financial statements. However, the impact of adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

GOODWILL IMPAIRMENT TESTING

In September 2011, the FASB issued ASU 2011-08, "Testing Goodwill for Impairment," which amends the guidance in ASC 350 on testing goodwill for impairment. Under the revised guidance, we have the option of performing a qualitative assessment before calculating the fair value of our reporting units. If it is determined in the qualitative assessment that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we would proceed to the two-step goodwill impairment test. Otherwise, no further impairment testing would be required. ASU 2011-08 is effective for us on January 1, 2012. The adoption of ASU 2011-08 is effective for both interim and annual goodwill tests and will give us the option to perform the qualitative assessment to determine the need for a two-step goodwill impairment test. The impact of the adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

DISCLOSURES ABOUT OFFSETTING ASSETS AND LIABILITIES

In December 2011, the FASB issued ASU 2011-11, "Disclosures About Offsetting Assets and Liabilities," which adds new disclosures to help financial statement users better understand the impact of offsetting arrangements on our balance sheet. The adoption of ASU 2011-11 will add disclosures showing both gross and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 is effective for us on January 1, 2013, and will be retroactively applied.

4. DIVESTITURES

We have completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. Included in discontinued operations, net of tax are amounts related to adjustments of our prior sales of diversified businesses. These adjustments are generally due to guarantees and indemnifications provided for certain legal, tax and environmental matters. See Note 22C for further discussion of our guarantees. The ultimate resolution of these matters could result in additional adjustments in future periods. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

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. During 2008, we also sold coal terminals and docks in West Virginia and Kentucky. The accompanying consolidated financial statements reflect the operations of our terminal operations and synthetic fuels businesses as discontinued operations.

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. See Note 22D for further discussion.

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

(in millions)	2011	2010	2009
Loss before income taxes and noncontrolling interest	$ (8)	$ (11)	$ (125)
Income tax benefit, including tax credits	3	5	47
Loss from discontinued operations attributable to controlling interests	$ (5)	$ (6)	$ (78)

The total income tax benefit presented in the preceding table includes deferred income tax benefit (expense) of $28 million, $124 million and $(86) million for the years ended December 31, 2011, 2010 and 2009, respectively, related to synthetic fuels tax credits.

B. OTHER DIVERSIFIED BUSINESSES

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses. During the years ended December 31, 2011, 2010 and 2009, gains and losses related to post-closing adjustments and pre-divestiture contingencies of other diversified businesses were not material to our results of operations.

5. PROPERTY, PLANT AND EQUIPMENT

A. UTILITY PLANT

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	2011	2010	2011	2010	2011	2010
Production plant	3-41	$ 16,728	$ 16,042	$ 9,978	$ 9,354	$ 6,585	$ 6,523
Transmission plant	7-75	3,853	3,530	1,825	1,626	2,028	1,904
Distribution plant	13-67	9,053	8,715	4,887	4,687	4,166	4,028
General plant and other	5-35	1,431	1,421	749	721	682	700
Utility plant in service		$ 31,065	$ 29,708	$ 17,439	$ 16,388	$ 13,461	$ 13,155

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 12). In the 2012 settlement agreement, PEF agreed to remove PEF's Crystal River Unit No. 3 Nuclear Plant (CR3) from rate base and will reclassify CR3 to a regulatory asset and suspend depreciation expense (See Note 8C).

As discussed in Note 8B, PEC intends to retire no later than December 31, 2013, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 megawatts (MW) at four sites. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. At December 31, 2011, the $15 million net carrying value of this retired facility is included in regulatory assets on the Consolidated Balance Sheets.

AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 8.7 percent in 2011 and 9.2 percent in 2010 and 2009. The composite AFUDC rate for PEF's electric utility plant was 7.4 percent, effective beginning April 1, 2010, based on its authorized return on equity (ROE) approved in the 2010 settlement agreement. This rate was unchanged by the 2012 settlement agreement (See Note 8C). Prior to April 1, 2010, the composite AFUDC rate for PEF's electric utility plant was 8.8 percent.

Our depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.3 percent, 2.0 percent and 2.4 percent in 2011, 2010 and 2009, respectively. The depreciation provisions related to utility plant and amortization of other utility plant, net were $675 million, $635 million and $626 million in 2011, 2010 and 2009, 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 5C) and regulatory approved expenses (See Notes 8 and 21).

PEC's depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.1 percent for 2011, 2010 and 2009. The depreciation provisions related to utility plant and amortization of other utility plant, net were $360 million, $338 million and $328 million in 2011, 2010 and 2009, 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 5C) and regulatory approved expenses (See Note 8B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4 percent in 2011, 1.9 percent in 2010 and 2.7 percent in 2009. The depreciation provisions related to utility plant were $315 million, $297 million and $299 million in 2011, 2010 and 2009, 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 5C) and regulatory approved expenses (See Note 8C).

During 2010, PEF updated the depreciation rates approved by the FPSC in the 2009 base rate case. The rate change was effective January 1, 2010, and resulted in a decrease in depreciation expense of $43 million for 2010. Additionally, in December 2010, PEF filed the FPSC-approved depreciation rates with the FERC for use in its formula transmission rate for its OATT. The FERC filing requested depreciation rates be applied retroactively to January 1, 2010, whereby, if approved, the depreciation rate changes would result in a reduction to the depreciation expense charged to PEF's OATT customers, beginning June 1, 2011. The FERC on July 15, 2011, rejected the proposed adjustments to depreciation reserves.

Nuclear fuel, net of amortization at December 31, 2011 and 2010, was $767 million and $674 million, respectively, for Progress Energy; $540 million and $480 million, respectively, for PEC; and $227 million and $194 million, respectively, for PEF. The amount not yet in service at December 31, 2011 and 2010, was $575 million and $367 million, respectively, for Progress Energy; $322 million and $199 million, respectively, for PEC; and $253 million and $168 million, respectively, for PEF. Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $160 million, $132 million and $159 million for the years ended December 31, 2011, 2010 and 2009, respectively. This amortization expense is included in fuel used in electric generation in the Consolidated Statements of Income. PEC's amortization of nuclear fuel costs for the years ended December 31, 2011, 2010 and 2009 was $160 million, $132 million and $134 million, respectively. PEF's amortization of nuclear fuel costs for the year ended December 31, 2009, was $25 million. PEF did not have any amortization of nuclear fuel costs for the years ended December 31, 2011 and 2010, due to the CR3 outage (See Note 8C).

PEF's construction work in progress related to certain nuclear projects receives regulatory treatment. At December 31, 2011, PEF had $555 million of accelerated recovery of construction work in progress, of which $177 million was a component of a nuclear cost-recovery clause regulatory asset. At December 31, 2010, PEF had $519 million of accelerated recovery of construction work in progress, of which $237 million was a component of a nuclear cost-recovery clause regulatory asset. See Note 8C for further discussion of PEF's nuclear cost recovery.

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. 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:

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
2011					
PEC	**Mayo**	**83.83 %**	**$ 807**	**$ 296**	**$ 13**
PEC	**Harris**	**83.83 %**	**3,254**	**1,635**	**66**
PEC	**Brunswick**	**81.67 %**	**1,739**	**951**	**52**
PEC	**Roxboro Unit 4**	**87.06 %**	**733**	**470**	**12**
PEF	**Crystal River Unit 3**	**91.78 %**	**909**	**498**	**803**
PEF	**Intercession City Unit P11**	**66.67 %**	**23**	**12**	**-**
2010					
PEC	Mayo	83.83 %	$ 798	$ 294	$ 8
PEC	Harris	83.83 %	3,255	1,604	16
PEC	Brunswick	81.67 %	1,702	939	38
PEC	Roxboro Unit 4	87.06 %	706	457	22
PEF	Crystal River Unit 3	91.78 %	901	497	648
PEF	Intercession City Unit P11	66.67 %	23	11	-

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.

In the tables above, construction work in progress for CR3 is not reduced by the accelerated recovery of qualifying project costs under the FPSC nuclear cost-recovery rule (see Note 8C).

C. ASSET RETIREMENT OBLIGATIONS

At December 31, 2011 and 2010, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $87 million and $90 million, respectively. PEC had immaterial asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2011 and 2010. Primarily due to the impact of updated escalation factors in 2010, as discussed below, at December 31, 2011 and 2010, PEF had no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant. At December 31, 2011 and 2010, additional PEF-related asset retirement costs, net of accumulated depreciation, of $87 million and $90 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' nuclear decommissioning trust (NDT) funds for the nuclear decommissioning liability totaled $1.647 billion and $1.571 billion at December 31, 2011 and 2010, respectively (See Notes 13 and 14). The fair value of funds set aside in the NDT funds for the nuclear decommissioning liability totaled $1.088 billion and $1.017 billion at December 31, 2011 and 2010, respectively, for PEC and $559 million and $554 million, respectively, for PEF (See Notes 13 and 14). Net NDT unrealized gains are included in regulatory liabilities (See Note 8A).

Progress Energy's and PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2011, 2010 and 2009. 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.

We recognized a benefit of $98 million in 2011 and expenses of $87 million and $141 million in 2010 and 2009, respectively, 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. PEC's related expenses were $125 million, $122 million and $106 million in 2011, 2010 and 2009, respectively. Due to a $250 million and $60 million cost of removal credit in 2011 and 2010, respectively, as allowed by the 2010 settlement agreement approved by the FPSC (See Note 8C), PEF recognized a benefit of $223 million and $35 million in 2011 and 2010, respectively. PEF's related expenses were $35 million in 2009.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, such costs consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Removal costs	**$ 1,302**	$ 1,503	**$ 1,065**	$ 1,000	**$ 237**	$ 503
Nonirradiated decommissioning costs	**223**	233	**185**	172	**38**	61
Dismantlement costs	**125**	121	**-**	-	**125**	121
Non-ARO cost of removal	**$ 1,650**	$ 1,857	**$ 1,250**	$ 1,172	**$ 400**	$ 685

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, in December 2009, which was filed with the NCUC on March 16, 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 8D for information about the NRC operating licenses held by PEC.

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 CR3 in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. 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 was not required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF was required to update the 2008 study with the most currently available escalation rates in 2010, which was filed with the FPSC in December 2010. We expect the FPSC to issue an order in 2012. 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 8D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate, assumed operating license renewal and updated escalation factors in 2010, PEF decreased its asset retirement cost to zero and its ARO liability by approximately $37 million in 2010. 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 2010 nuclear decommissioning filing. No nuclear decommissioning reserve accrual is recorded at PEF 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. As a result of the base rate case, the FPSC approved an annual fossil dismantlement accrual of $4 million. PEF's reserve for fossil plant dismantlement was approximately $148 million and $144 million at December 31, 2011 and 2010, including amounts in the ARO liability for asbestos abatement, discussed below.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $23 million and $26 million at December 31, 2011 and 2010, respectively, at PEC and $29 million and $27 million at December 31, 2011 and 2010, 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 $6 million and $3 million at December 31, 2011 and 2010, respectively, at PEC and $7 million and $6 million at December 31, 2011 and 2010, respectively, at PEF.

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. Revisions to prior estimates of the PEC and PEF regulated ARO are primarily 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, 2010	$ 1,170	$ 801	$ 369
Additions	4	4	-
Accretion expense	65	46	19
Revisions to prior estimates	(39)	(2)	(37)
Asset retirement obligations at December 31, 2010	1,200	849	351
Accretion expense	**67**	**49**	**18**
Revisions to prior estimates	**(2)**	**(2)**	**-**
Asset retirement obligations at December 31, 2011	**$ 1,265**	**$ 896**	**$ 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 amounts ranging from $3.5 million to $4.5 million per week. Additional weeks of coverage ranging from 71 weeks to 110 weeks are 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 $29 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. At December 31, 2011, PEF has an outstanding claim with NEIL for CR3 (See Notes 6 and 8C).

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 and has a regulatory mechanism to recover the costs of named storms on an expedited basis (See Note 8C).

For loss or damage to non-nuclear properties, excluding self-insured transmission and distribution lines, the Utilities are insured under an all-risk property insurance program with a total limit of $600 million per loss. The basic deductible is $2.5 million per loss, and there is no outage or replacement power coverage under this program.

6. 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)	**2011**	2010	**2011**	2010	**2011**	2010
Trade accounts receivable	**$ 520**	$ 651	**$ 276**	$ 346	**$ 244**	$ 303
Unbilled accounts receivable	**157**	223	**102**	136	**55**	87
Other receivables	**168**	75	**123**	47	**20**	12
NEIL receivable (Note 8C)	**71**	119	**-**	-	**71**	119
Allowance for doubtful receivables	**(27)**	(35)	**(9)**	(10)	**(18)**	(25)
Total receivables, net	**$ 889**	$ 1,033	**$ 492**	$ 519	**$ 372**	$ 496

Other receivables for Progress Energy and PEC above include $92 million at December 31, 2011, related to the award from the DOE for asserted damages associated with spent nuclear fuel (See Note 22D).

7. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Fuel for production	**$ 681**	$ 542	**$ 323**	$ 192	**$ 358**	$ 350
Materials and supplies	**747**	676	**446**	395	**301**	281
Emission allowances	**4**	8	**1**	3	**3**	5
Other	**6**	-	**5**	-	**1**	-
Total inventory	**$ 1,438**	$ 1,226	**$ 775**	$ 590	**$ 663**	$ 636

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 $28 million, $4 million and $24 million, respectively, at December 31, 2011. Long-term emission allowances for Progress Energy, PEC and PEF were $33 million, $5 million and $28 million, respectively, at December 31, 2010.

8. REGULATORY MATTERS

On January 8, 2011, Progress Energy and Duke Energy entered into the Merger Agreement. See Note 2 for regulatory information related to the Merger with Duke Energy.

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. Regulatory assets may be recorded for certain employee benefit costs of unregulated affiliates that will be allocated to the Utilities and recovered through rates of the Utilities. Our and 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)	2011	2010
Deferred fuel costs – current (Notes 8B and 8C)	$ 275	$ 169
Nuclear deferral (Note 8C)	-	7
Total current regulatory assets	275	176
Nuclear deferral (Note 8C)[a]	117	178
Deferred impact of ARO (Note 5C)[b]	137	122
Income taxes recoverable through future rates[c]	352	302
Loss on reacquired debt[d]	29	31
Postretirement benefits (Note 17)[e]	1,506	1,105
Derivative mark-to-market adjustment (Note 18A)[f]	708	505
DSM/Energy-efficiency deferral (Note 8B)[g]	92	57
Other	84	74
Total long-term regulatory assets	3,025	2,374
Environmental (Note 8C)	(7)	(45)
Energy conservation (Note 8C)	(19)	(11)
Nuclear deferral (Note 8C)	(15)	-
Other current regulatory liabilities	(7)	(3)
Total current regulatory liabilities	(48)	(59)
Amount to be refunded to customers (Note 8C)[h]	(288)	-
Non-ARO cost of removal (Note 5C)[b]	(1,650)	(1,857)
Deferred impact of ARO (Note 5C)[b]	(146)	(143)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]	(412)	(421)
Storm reserve (Note 8C)[j]	(132)	(136)
Other	(72)	(78)
Total long-term regulatory liabilities	(2,700)	(2,635)
Net regulatory assets (liabilities)	$ 552	$ (144)

PEC

(in millions)	2011	2010
Deferred fuel costs – current (Note 8B)	$ 31	$ 71
Deferred impact of ARO (Note 5C)[b]	124	112
Income taxes recoverable through future rates[c]	140	103
Loss on reacquired debt[d]	12	13
Postretirement benefits (Note 17)[e]	691	545
Derivative mark-to-market adjustment (Note 18A)[f]	200	121
DSM/Energy-efficiency deferral (Note 8B)[g]	92	57
Other	51	36
Total long-term regulatory assets	1,310	987
Deferred fuel costs – current (Note 8B)	(2)	-
Non-ARO cost of removal (Note 5C)[b]	(1,250)	(1,172)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]	(266)	(267)
Other	(27)	(22)
Total long-term regulatory liabilities	(1,543)	(1,461)
Net regulatory liabilities	$ (204)	$ (403)

PEF

(in millions)	2011	2010
Deferred fuel costs – current (Note 8C)	$ 244	$ 98
Nuclear deferral (Note 8C)	-	7
Total current regulatory assets	244	105
Nuclear deferral (Note 8C)[a]	117	178
Income taxes recoverable through future rates[c]	212	199
Loss on reacquired debt[d]	17	18
Postretirement benefits (Note 17)[e]	702	560
Derivative mark-to-market adjustment (Note 18A)[f]	508	384
Other	46	48
Total long-term regulatory assets	1,602	1,387
Environmental (Note 8C)	(7)	(45)
Energy conservation (Note 8C)	(19)	(11)
Nuclear deferral (Note 8C)	(15)	-
Other current regulatory liabilities	(5)	(3)
Total current regulatory liabilities	(46)	(59)
Amount to be refunded to customers (Note 8C)[h]	(288)	-
Non-ARO cost of removal (Note 5C)[b]	(400)	(685)
Deferred impact of ARO (Note 5C)[b]	(45)	(47)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]	(146)	(154)
Storm reserve (Note 8C)[j]	(132)	(136)
Other	(60)	(62)
Total long-term regulatory liabilities	(1,071)	(1,084)
Net regulatory assets	$ 729	$ 349

The recovery and amortization periods for these regulatory assets and (liabilities) at December 31, 2011, 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 over the related property lives, which may range up to 65 years, and will be settled and adjusted following completion of the related activities.

[c] Income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years.

[d] 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.

[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 17).

[f] Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After contract settlement and consumption of the related fuel, the realized gains or losses are passed through the fuel cost-recovery clause.

[g] Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

[h] Recorded as a result of the 2012 settlement agreement to be refunded to customers through the fuel clause over four years beginning in 2013 (see Note 8C).

[i] Related to unrealized gains and losses on NDT funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

[j] Utilized as storm restoration expenses are incurred.

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 base rate cases in 1988, the NCUC and the SCPSC each authorized a ROE of 12.75 percent.

COST RECOVERY FILINGS

On November 14, 2011, the NCUC approved PEC's settlement agreement for an $85 million increase in the fuel rate charged to its North Carolina retail ratepayers, driven by rising fuel prices. The settlement agreement updated certain costs from PEC's original filing and included the impact of a $24 million disallowance of replacement power costs resulting from prior-year performance of PEC's nuclear plants. The increase was effective December 1, 2011, and increased residential electric bills by $2.75 per 1,000 kilowatt-hours (kWh) for fuel cost recovery. Also on November 14, 2011, the NCUC approved PEC's request for a $24 million increase in the demand-side management (DSM) and EE rate charged to its North Carolina ratepayers. The increase was effective December 1, 2011, and increased the residential electric bills by $1.08 per 1,000 kWh for DSM and EE cost recovery. On November 10, 2011, the NCUC approved PEC's request for a $9 million increase for North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The increase was effective December 1, 2011, and decreased the residential electric bills by $0.02 per 1,000 kWh. The residential NC REPS rate decreased while the total amount to be recovered increased due to the allocation of the NC REPS recovery between customer classes. The net impact of the settlement agreement and filings results in an average increase in residential electric bills of 3.7 percent. At December 31, 2011, PEC's North Carolina deferred fuel and DSM/EE balances were $31 million and $78 million, respectively.

On June 29, 2011, the SCPSC approved a $22 million increase in the fuel rate charged to its South Carolina ratepayers, driven by rising fuel prices. The increase was effective July 1, 2011, and increased residential electric bills by $3.45 per 1,000 kWh. Also on June 29, 2011, the SCPSC approved a $4 million increase in the DSM and EE rate. The increase was effective July 1, 2011, and increased residential electric bills by $1.25 per 1,000 kWh. The net impact of the two filings resulted in an average increase in residential electric bills of 4.7 percent. At December 31, 2011, PEC's South Carolina deferred fuel and DSM/EE balances were $(2) million and $14 million, respectively.

OTHER MATTERS

Construction of Generating Facilities

On June 1, 2011, a newly constructed 600-MW combined cycle natural gas-fueled unit at the Smith Energy Complex was placed in service.

On October 22, 2009, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility will be in service by January 2013.

On June 9, 2010, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C., to replace the existing coal-fired generation at this site. PEC projects that the generating facility will be in service in December 2013.

Planned Retirements of Generating Facilities

PEC filed a plan with the NCUC and the SCPSC to retire 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. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. PEC expects to retire the remaining coal-fired facilities by the end of 2013.

The net carrying value of the three remaining facilities at December 31, 2011, of $163 million is included in other utility plant, net on the Consolidated Balance Sheets. Consistent with ratemaking treatment, PEC will continue to depreciate each plant using the current depreciation lives and rates on file with the NCUC and the SCPSC until the earlier of the plant's retirement or PEC's completion and filing of a new depreciation study on or before March 31, 2013. The net carrying value of the retired facility at December 31, 2011, of $15 million is included in regulatory assets on the Consolidated Balance Sheets. PEC expects to include the four facilities' remaining net carrying value in rate base after retirement. The final recovery periods may change in connection with the regulators' determination of the recovery of the remaining net carrying value.

C. PEF RETAIL RATE MATTERS

CR3 OUTAGE

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete at the periphery of the containment building, which resulted in an extension of the outage. After analysis, PEF determined that the concrete delamination at CR3 was caused by redistribution of stresses in the containment wall that occurred when PEF created an opening to accommodate the replacement of the unit's steam generators. In March 2011, the work to return the plant to service was suspended after monitoring equipment at the repair site identified a new delamination that occurred in a different section of the outer wall after the repair work was completed and during the late stages of retensioning the containment building. CR3 has remained out of service while PEF conducted an engineering analysis and review of the new delamination and evaluated repair options. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process.

PEF analyzed multiple repair options as well as early decommissioning and believes, based on the information and analyses conducted to date, that repairing the unit is the best option. PEF engaged outside engineering consultants to perform the analysis of possible repair options for the containment building. The consultants analyzed 22 potential repair options and ultimately narrowed those to four. PEF, along with other independent consultants, reviewed the four options for technical issues, constructability, and licensing feasibility as well as cost.

Based on that initial analysis, PEF selected the best repair option, which would entail systematically removing and replacing concrete in substantial portions of the containment structure walls. The planned option does not include the area where concrete was replaced during the initial repair. The preliminary cost estimate for this repair as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion. Engineering design of the repair is under way. PEF will update the current estimate as this work is completed.

PEF is moving forward systematically and will perform additional detailed engineering analyses and designs, which could affect any repair plan. This process will lead to more certainty for the cost and schedule of the repair. PEF will continue to refine and assess the plan, and the prudence of continuing to pursue it, based on new developments and analyses as the process moves forward. Under this repair plan, PEF estimates that CR3 will return to service in 2014. The decision related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to, the cost of repair and the likelihood of obtaining NRC approval to restart CR3 after repair. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments.

PEF maintains insurance for property damage and incremental costs of replacement power resulting from prolonged accidental outages through NEIL as discussed in Note 5D. NEIL has confirmed that the CR3 initial delamination is a covered accident but has not yet made a determination as to coverage for the second delamination. Following a 12-week deductible period, the NEIL program provided reimbursement for replacement power costs for 52 weeks at $4.5 million per week, through April 9, 2011. An additional 71 weeks of coverage, which runs through August 2012, is provided at $3.6 million per week. Accordingly, the NEIL program provides replacement power coverage of up to $490 million per event. Actual replacement power costs have exceeded the insurance coverage through December 31, 2011. PEF anticipates that future replacement power costs will continue to exceed the insurance

coverage. PEF also maintains insurance coverage through NEIL's accidental property damage program, which provides insurance coverage up to $2.25 billion with a $10 million deductible per claim.

PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. PEF has not yet received a definitive determination from NEIL about the insurance coverage related to the second delamination. In addition, no replacement power reimbursements were received from NEIL in the second half of 2011. These considerations led us to conclude that at December 31, 2011, it was not probable that NEIL will voluntarily pay the full coverage amounts we believe they owe under the applicable insurance policies. Given the circumstances, accounting standards require full recovery to be probable to recognize an insurance receivable. Therefore, PEF has suspended recording any further insurance receivables from NEIL related to the second delamination and removed the associated $222 million NEIL receivable. PEF recorded a corresponding $154 million addition to its deferred fuel regulatory asset and a $68 million addition to construction work in progress. Negotiations continue with NEIL regarding coverage associated with the second delamination, and PEF continues to believe that all applicable costs associated with bringing CR3 back into service are covered under all insurance policies.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2011:

(in millions)	Replacement power costs	Repair costs
Spent to date	$ 478	$ 258
NEIL proceeds received	(162)	(136)
Insurance receivable at December 31, 2011, net	(55)	(3)
Balance for recovery[(a)]	$ 261	$ 119

(a) See "2012 Settlement Agreement" and "Fuel Cost Recovery" below for discussion of PEF's ability to recover prudently incurred fuel and purchase power costs and CR3 repair costs.

PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. Additionally, we cannot be assured that CR3 can be repaired and brought back to service until full engineering and other analyses are completed.

On October 25, 2010, the FPSC approved PEF's motion to establish a separate spin-off docket to review the prudence and costs related to the outage and replacement fuel and power costs associated with the CR3 extended outage. The FPSC subsequently issued an order dividing the docket into three phases. The first phase will include a prudence review of the events and decisions of PEF leading up to the first delamination event. The second phase will be a consideration of the prudence of PEF's decision to repair or decommission CR3. The third phase of this docket will include the decisions and events subsequent to the first delamination leading up to the March 14, 2011 delamination event and the subsequent repair of the containment building. See "2012 Settlement Agreement – CR3" below for a discussion of the resolution of this docket.

2012 SETTLEMENT AGREEMENT

On February 22, 2012, the FPSC approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The 2012 settlement agreement will continue through the last billing cycle of December 2016. The agreement addresses three principal matters: PEF's proposed Levy Nuclear Power Plant (Levy) Nuclear Project cost recovery, the CR3 delamination prudence review pending before the FPSC, and certain base rate issues. When all of the settlement provisions are factored in, the total increase in 2013 for residential customer bills will be approximately $4.93 per 1,000 kWh, or 4 percent.

Levy

Under the terms of the 2012 settlement agreement, PEF will set the residential cost-recovery factor of PEF's proposed two units at Levy (see "Nuclear Cost Recovery – Levy Nuclear") at $3.45 per 1,000 kWh effective in the first billing cycle of January 2013 and continuing for a five-year period. This amount is intended to recover the estimated retail project costs to date plus costs necessary to obtain the combined license (COL) and any engineering, procurement and construction (EPC) cancellation costs, if PEF ultimately chooses to cancel that contract. PEF will not recover any additional Levy costs from customers through the term of the agreement, or file for any additional recovery before March 1, 2017, unless otherwise agreed to by the parties to the agreement. In addition, the consumer parties will not oppose PEF continuing to pursue a COL for Levy. After the five-year period, PEF will true up any actual costs not recovered under the Levy cost-recovery factor.

The 2012 settlement agreement also provides that PEF will treat the allocated wholesale cost of Levy as a retail regulatory asset and include this asset as a component of rate base and amortization expense for regulatory reporting. PEF will have the discretion to suspend such amortization in full or in part provided that PEF amortizes all of the regulatory asset by December 31, 2016.

CR3

Under the terms of the 2012 settlement agreement, PEF will be permitted to recover prudently incurred fuel and purchased power costs through the fuel clause without regard for the absence of CR3 for the period from the beginning of the CR3 outage through the earlier of the term of the agreement or the return of CR3 to commercial service. If PEF does not begin repairs of CR3 prior to the end of 2012, PEF will refund replacement power costs on a pro rata basis based on the in-service date of up to $40 million in 2015 and $60 million in 2016. The parties to the agreement waive their right to challenge PEF's recovery of these costs. The parties to the agreement maintain the right to challenge the prudence and reasonableness of PEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the CR3 outage. All prudence issues from the steam generator project inception through the date of settlement approval by the FPSC are resolved.

To the extent that PEF pursues the repair of CR3, PEF will establish an estimated cost and repair schedule with ongoing consultation with the parties to the agreement. The established cost, to be approved by our board of directors, will be the basis for project measurement. If costs exceed the board-approved estimate, overruns will be split evenly between our shareholders and PEF customers up to $400 million. The parties to the agreement agree to meet to discuss the method of recovery of any overruns in excess of $400 million, with final decision by the FPSC if resolution cannot be reached. If the repairs begin prior to the end of 2012, the parties to the agreement waive their rights to challenge PEF's decision to repair and the repair plan chosen by PEF. In addition, there will be limited rights to challenge recovery of the repair execution costs incurred prior to the final resolution on NEIL coverage. The parties to the agreement will discuss the treatment of any potential gap between NEIL repair coverage and the estimated cost, with final decision by the FPSC if resolution cannot be reached. If the repairs do not begin prior to the end of 2012, the parties to the agreement reserve the right to challenge the prudence of PEF's repair decision, plan and implementation.

PEF also retains sole discretion and flexibility to retire the unit without challenge from the parties to the agreement. If PEF decides to retire CR3, PEF is allowed to recover all remaining CR3 investments and to earn a return on the CR3 investments set at its current authorized overall cost of capital, adjusted to reflect a ROE set at 70 percent of the current FPSC-authorized ROE, no earlier than the first billing cycle of January 2017. Additionally, any NEIL proceeds received after the settlement will be applied first to replacement power costs incurred after December 31, 2012, with the remainder used to write down the remaining CR3 investments.

Base Rates, Customer Refund and Other Terms

Under the terms of the 2012 settlement agreement, PEF will maintain base rates at the current levels through the last billing cycle of December 2016, except as described as follows. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current ROE range of 9.5 percent to 11.5 percent. PEF will suspend depreciation expense and reverse certain regulatory liabilities associated with CR3 effective on the implementation date of the agreement. Additionally, rate base

associated with CR3 investments will be removed from retail rate base effective with the first billing cycle of January 2013. PEF will accrue, for future rate-setting purposes a carrying charge at a rate of 7.4 percent on the CR3 investment until CR3 is returned to service and placed back into retail rate base. Upon return of CR3 to commercial service, PEF will be authorized to increase its base rates for the annual revenue requirements of all CR3 investments. The parties to the agreement reserve the right to participate in any hearings challenging the appropriateness of PEF's CR3 revenue requirements. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. If PEF's retail base rate earnings fall below the ROE range, as reported on a FPSC-adjusted or pro-forma basis on a PEF monthly earnings surveillance report, PEF may petition the FPSC to amend its base rates during the term of the agreement.

Under the terms of the 2012 settlement agreement, PEF will refund $288 million as of December 31, 2011, to customers through the fuel clause. PEF will refund $129 million in each of 2013 and 2014, and an additional $10 million annually to residential and small commercial customers in 2014, 2015 and 2016. At December 31, 2011, a regulatory liability was established for the $288 million to be refunded in future periods. The corresponding charge was recorded as a reduction of 2011 revenues.

The cost of pollution control equipment that PEF installed and has in-service at CR4 and CR5 to comply with the Federal Clean Air Interstate Rule (CAIR) is currently recovered under the Environmental Cost Recovery Clause (ECRC). The 2012 settlement agreement provides for PEF to remove those assets from recovery in the ECRC and transfer those assets to base rates effective with the first billing cycle of January 2014. The related base rate increase will be in addition to the $150 million base rate increase effective January 2013. O&M expenses associated with those assets will not be included in the base rates and will continue to be recovered through the ECRC.

The 2012 settlement agreement provides for PEF to continue to recover carrying costs and other nuclear cost recovery clause-recoverable items related to the CR3 uprate project, but PEF will not seek an in-service recovery until nine months following CR3's return to commercial service. Carrying costs will be recovered through the nuclear cost recovery clause until base rates have been increased for these assets.

The 2012 settlement agreement also allows PEF to continue to reduce amortization expense (cost of removal component) beyond the expiration of the 2010 settlement agreement through the term of the 2012 settlement agreement. This reduction is limited by the eligible remaining balance of the cost of removal reserve ($246 million at December 31, 2011). Additionally, the 2012 settlement agreement extends PEF's ability to expedite recovery of the cost of named storms and to maintain a storm reserve at its level as of the implementation date of the agreement, and removed the maximum allowed monthly surcharge established by the 2010 settlement agreement.

2010 SETTLEMENT AGREEMENT

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. The settlement agreement also provides that PEF will have the discretion to reduce amortization expense (cost of removal component) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in the cost of removal reserve in 2012 until the earlier of (a) PEF's applicable cost of removal reserve reaches zero, or (b) the expiration of the settlement agreement at the end of 2012. In the event PEF reduces amortization expense by less than the annual amounts for 2010 or 2011, PEF may carry forward (i.e., increase the annual cap by) any unused cost of removal reserve amounts in subsequent years during the term of the agreement. The balance of the cost of removal reserve is impacted by accruals in accordance with PEF's latest depreciation study, removal costs expended and reductions in amortization expense as permitted by the settlement agreement. For the year ended December 31, 2011, PEF recognized a $250 million reduction in amortization expense pursuant to the settlement agreement. PEF had eligible cost of removal reserves of $246 million remaining at December 31, 2011. The settlement agreement also provides PEF with the opportunity to earn a ROE of up to 11.5 percent and provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro-forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited or interim base rate relief, or any combination thereof. Prior to requesting any such relief, PEF must have reflected on its referenced surveillance report associated amortization expense reductions of at least $150 million. The settlement agreement does not

preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been or are presently recovered through cost-recovery clauses or surcharges; or (b) that are incremental costs not currently recovered in base rates, which the legislature or FPSC determines are clause recoverable; or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. PEF also may, at its discretion, accelerate in whole or in part the amortization of certain regulatory assets over the term of the settlement agreement. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis after depletion of the storm damage reserve. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period, PEF can begin recovery, subject to refund, through a surcharge of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to $136 million, the level as of June 1, 2010, after storm costs are fully recovered. At December 31, 2011, PEF's storm damage reserve was $132 million.

On September 14, 2010, the FPSC approved a reduction to PEF's AFUDC rate, from 8.8 percent to 7.4 percent. This new rate is based on PEF's updated authorized ROE and all adjustments approved on January 11, 2010, in PEF's base rate case and will be used for all purposes except for nuclear recoveries with original need petitions submitted on or before December 31, 2010, as permitted by FPSC regulations.

FUEL COST RECOVERY

On November 22, 2011, the FPSC approved an increase of the total fuel-cost recovery by $162 million, increasing the residential rate by $3.32 per 1,000 kWh, or 2.78 percent, effective January 1, 2012. This increase is due to an increase of $3.99 per 1,000 kWh for the projected recovery of fuel costs offset by a decrease of $0.67 per 1,000 kWh for the projected recovery through the Capacity Cost-Recovery Clause (CCRC). The increase in the projected recovery of fuel costs is due to an under-recovery from the prior year. The decrease in the CCRC is primarily due to lower anticipated costs associated with Levy, and the deferral of 2011 and 2012 estimated costs associated with PEF's CR3 uprate project until 2012 (see "Nuclear Cost Recovery"), partially offset by increased capacity costs and a reduction of the refund related to an over-recovery from the prior year. Within the fuel clause, PEF received approval to collect, subject to refund, replacement power costs related to the CR3 nuclear plant outage (See "CR3 Outage" and "2012 Settlement Agreement").

At December 31, 2011, PEF's deferred fuel regulatory liability was $44 million comprised of a $244 million current regulatory asset and a $288 million noncurrent regulatory liability (See "2012 Settlement Agreement"). The current regulatory asset of $244 million includes the $154 million of replacement power costs that were previously recorded as a receivable from NEIL (See "CR3 Outage").

NUCLEAR COST RECOVERY

Levy Nuclear

In 2008, the FPSC granted PEF's petition for an affirmative Determination of Need and related orders requesting cost recovery under Florida's nuclear cost-recovery rule for Levy, together with the associated facilities, including transmission lines and substation facilities. Levy is needed to maintain electric system reliability and integrity, provide fuel and generating diversity, and allow PEF to continue to provide adequate electricity to its customers at a reasonable cost. The proposed Levy units 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 No. 1 would be placed in service by June 2016 and Levy Unit No. 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units No. 1 and No. 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities.

In PEF's 2010 nuclear cost-recovery filing (See "Cost Recovery"), PEF identified a schedule shift in the Levy project that resulted from the NRC's 2009 determination that certain schedule-critical work that PEF had proposed to perform within the scope of its Limited Work Authorization request submitted with the COL application will not be authorized until the NRC issues the COL. Consequently, major construction activities on Levy have been

postponed until after the NRC issues the COL for the units, which is expected in 2013 if the current licensing schedule remains on track. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, cost; potential carbon regulation; fossil fuel prices; the benefits of fuel diversification; public, regulatory and political support; adequate financial cost-recovery mechanisms; appropriate levels of joint owner participation; customer rate impacts; project feasibility; DSM and EE programs; and availability and terms of capital financing. Taking into account these criteria, we consider Levy to be PEF's preferred baseload generation option.

Crystal River Unit No. 3 Nuclear Plant Uprate

In 2007, the FPSC issued an order approving PEF's Determination of Need petition related to a multi-stage uprate of CR3 that will increase CR3's gross output by approximately 180 MW during its next refueling outage. PEF implemented the first-stage design modifications in 2008. The final stage of the uprate required a license amendment to be filed with the NRC, which was filed by PEF in June 2011 and accepted for review by the NRC on November 21, 2011.

Cost Recovery

In 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consisted 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. The FPSC approved the alternate proposal allowing PEF to recover 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. 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. The rate management plan included the 2009 reclassification to the nuclear cost-recovery clause regulatory asset of $198 million of capacity revenues and 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 the end of 2014. At December 31, 2011, PEF's nuclear cost-recovery regulatory asset was $102 million, comprised of a $15 million current regulatory liability and a $117 million noncurrent regulatory asset. PEF will continue to recover nuclear costs as provided for by the 2012 settlement agreement.

On October 24, 2011, the FPSC approved a $78 million decrease in the amount charged to PEF's ratepayers for nuclear cost recovery, which is a component of, and is included in, the fuel cost recovery (See "Fuel Cost Recovery"), including recovery of preconstruction and carrying costs and CCRC-recoverable O&M expense anticipated to be incurred during 2012, recovery of $60 million of prior years' deferrals in 2012, as well as the estimated actual true-up of 2011 costs associated with the Levy and CR3 uprate projects. Also included is the stipulation of PEF's filed motion with the FPSC to defer until 2012 the approval of the long-term feasibility analysis of completing the CR3 uprate, and the determination of reasonableness on, and recovery of, 2011 and 2012 estimated costs. This resulted in an estimated decrease in the nuclear cost-recovery charge of $2.67 per 1,000 kWh for residential customers, beginning with the first January 2012 billing cycle.

DEMAND-SIDE MANAGEMENT COST RECOVERY

On July 26, 2011, the FPSC voted to set PEF's DSM compliance goals to remain at their current level until the next goal setting docket is initiated. An intervener filed a protest to the FPSC's Proposed Agency Action order, asserting legal challenges to the order. The parties made legal arguments to the FPSC and the FPSC issued an order denying the protest on December 22, 2011. The intervener then filed a notice of appeal of this order to the Florida Supreme Court on January 17, 2012. We cannot predict the outcome of this matter.

On November 1, 2011, the FPSC approved PEF's request to decrease the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.11 per 1,000 kWh, or 0.1 percent of the total residential rate, effective January 1, 2012. The decrease in the ECCR is primarily due to an increased refund of a prior period over-recovery, partially

offset by an increase in conservation program costs. At December 31, 2011, PEF's over-recovered deferred ECCR balance was $19 million.

OTHER MATTERS

On November 22, 2011, the FPSC approved PEF's request to increase the ECRC by $24 million, increasing the residential rate by $0.54 per 1,000 kWh, or 0.5 percent, effective January 1, 2012. The increase in the ECRC is primarily due to the 2011 rates including a return of a prior period over-recovery, partially offset by a decrease in the related O&M expense. At December 31, 2011, PEF's over-recovered deferred ECRC was $7 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. 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 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 did 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. As of December 31, 2011, PEF has not recorded any amortization related to the deferred pension regulatory asset. The 2012 settlement agreement allows for accelerated amortization of all or part of this deferred pension regulatory asset.

D. NUCLEAR LICENSE RENEWALS

PEC's nuclear units are currently operating under licenses that expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF applied for a 20-year renewal of the license in 2008. The NRC's remaining open items in the license renewal process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

9. 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 reporting units and our goodwill impairment tests are performed at the utility reporting unit level. At December 31, 2011 and 2010, 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 October 31 of each year. The results of our 2011 annual test of goodwill indicated that the carrying amounts of goodwill were not impaired.

10. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2011 and December 31, 2010, we had 500 million shares of common stock authorized under our charter, of which 295 million and 293 million shares were outstanding, respectively. We periodically issue shares of common stock through the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)), the Progress Energy Investor Plus Plan (IPP) and other benefit plans.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings (See Note 2 and Note 12B).

The following table presents information for our common stock issuances for the years ended December 31:

	2011		2010		2009	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**2.0**	**$ 53**	12.2	$ 434	17.5	$ 623
Issuances under an underwritten public offering[a]	-	-	-	-	14.4	523
Issuances through 401(k) and/or IPP	-	**1**	11.2	431	2.5	100

[a] The shares issued under an underwritten public offering were issued on January 12, 2009, at a public offering price of $37.50.

PEC

At December 31, 2011 and December 31, 2010, 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, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B for additional dividend restrictions related to PEC.

PEF

At December 31, 2011 and December 31, 2010, 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, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B 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. 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 was held by the 401(k) Trustee in a suspense account. The common stock was released from the suspense account and made available for allocation to participants as the ESOP loan was repaid. Such allocations were 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. By December 31, 2010, no ESOP suspense shares were outstanding and the ESOP acquisition loan was repaid.

ESOP shares allocated to plan participants totaled 13.4 million at December 31, 2010. Our matching compensation cost under the 401(k) is determined based on matching percentages as defined in the plan. Through December 31, 2010, such compensation cost was allocated to participants' accounts in the form of Progress Energy common stock. Beginning in 2011, such compensation cost was allocated to participants' accounts in the same investments and

election percentages as the participants' contributions. In 2010, we met common stock share needs with open market purchases and with shares released from the ESOP suspense account. Matching costs met with shares released from the suspense account totaled $12 million for the years ended December 31, 2010 and 2009, respectively. In 2011, we met common stock share needs with open market purchases.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation, which is an ESOP plan that covers bargaining unit employees of PEF.

Total matching cost for both plans was $44 million, $43 million and $41 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEC

PEC's matching costs met with shares released from the ESOP suspense account totaled $8 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost was $23 million, $23 million and $22 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEF

PEF's matching costs met with shares released from the ESOP suspense account totaled $3 million and $4 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost for both plans was $14 million, $14 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 Equity Incentive Plan (EIP) and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time. As authorized by the EIPs, we may grant up to 20 million shares of Progress Energy common stock through our long-term compensation program.

Beginning in 2009, shares issued under the redesigned PSSP 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. 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. At December 31, 2011, there were an immaterial number of stock-settled performance target shares outstanding. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

Beginning in 2007, we began issuing restricted stock units (RSUs) rather than the previously issued 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 three- 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 and are converted to shares upon vesting. At December 31, 2011, there were an immaterial number of RSUs outstanding.

The total fair value of RSUs vested during the years ended December 31, 2011, 2010 and 2009, was $24 million, $24 million and $16 million, respectively. No cash was expended to purchase stock to satisfy RSU plan obligations in 2011, 2010 and 2009. The RSUs vested during 2011 had a weighted-average grant date fair value of $39.16.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $33 million for the year ended December 31, 2011, with a recognized tax benefit of $13 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $27

million, with a recognized tax benefit of $11 million, and $37 million, with a recognized tax benefit of $14 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2011, unrecognized compensation cost related to nonvested other stock-based compensation plan awards totaled $33 million, which is expected to be recognized over a weighted-average period of 1.6 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $20 million for the year ended December 31, 2011, with a recognized tax benefit of $8 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $16 million, with a recognized tax benefit of $6 million, and $22 million, with a recognized tax benefit of $9 million, for the years ended December 31, 2010 and 2009, 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, 2011, 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 $11 million, with a recognized tax benefit of $4 million, and $14 million, with a recognized tax benefit of $5 million, for the years ended December 31, 2010 and 2009, 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)	**2011**	2010	2009
Weighted-average common shares – basic	**295.8**	290.7	279.4
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.1
Weighted-average shares – fully diluted	**295.9**	290.8	279.5

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. There were 0.8 million and 1.5 million stock options outstanding at December 31, 2010 and 2009, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive. As of December 31, 2011, there were no antidilutive stock options outstanding.

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)	**2011**	2010	**2011**	2010	**2011**	2010
Cash flow hedges	**$ (143)**	$ (63)	**$ (71)**	$ (33)	**$ (27)**	$ (4)
Pension and other postretirement benefits	**(22)**	(62)	**-**	-	**-**	-
Total accumulated other comprehensive loss	**$ (165)**	$ (125)	**$ (71)**	$ (33)	**$ (27)**	$ (4)

11. 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 for an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC's 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, 2011 and 2010, 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	236,997	$ 110.00	$ 24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	-	-	-
No par value Preference Stock	10,000,000	-	-	-
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	-	-	-
$100 par value Preference Stock	1,000,000	-	-	-
Total PEF				34
Total preferred stock of subsidiaries				$ 93

12. DEBT AND CREDIT FACILITIES

A. DEBT AND CREDIT FACILITIES

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2011):

(in millions)		2011	2010
Parent			
Senior unsecured notes, maturing 2012-2039	6.28 %	**$ 4,000**	$ 4,200
Unamortized premium and discount, net		**(7)**	(6)
Current portion of long-term debt		**(450)**	(205)
Long-term debt, net		**3,543**	3,989
PEC			
First mortgage bonds, maturing 2013-2038	5.17 %	**3,025**	2,525
First mortgage bonds/pollution control obligations, maturing 2017-2024	0.57 %	**669**	669
Senior unsecured notes, maturing 2012	6.50 %	**500**	500
Miscellaneous notes	6.00 %	**5**	5
Unamortized premium and discount, net		**(6)**	(6)
Current portion of long-term debt		**(500)**	-
Long-term debt, net		**3,693**	3,693
PEF			
First mortgage bonds, maturing 2013-2040	5.56 %	**4,100**	4,100
First mortgage bonds/pollution control obligations, maturing 2018-2027	0.57 %	**241**	241
Medium-term notes, maturing 2028	6.75 %	**150**	150
Unamortized premium and discount, net		**(9)**	(9)
Current portion of long-term debt		**-**	(300)
Long-term debt, net		**4,482**	4,182
Progress Energy consolidated long-term debt, net		**$ 11,718**	$ 11,864
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10 %	**$ 309**	$ 309
Unamortized premium and discount, net		**(36)**	(36)
Long-term debt, affiliate		**$ 273**	$ 273

On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due January 15, 2021. The net proceeds of $495 million, along with available cash on hand, were used to retire the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011. Accordingly, we classified $495 million of the Parent's $700 million 7.10% Senior Notes due March 1, 2011 as long-term debt at December 31, 2010.

On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt.

On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with a portion of the proceeds from the $950 million of Senior Notes issued on November 19, 2009.

On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due April 1, 2020, and $350 million of 5.65% First Mortgage Bonds due April 1, 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

At December 31, 2011 and 2010, we had committed lines of credit used to support our commercial paper and other short-term borrowings. At December 31, 2011 and 2010, we had no outstanding borrowings under our revolving credit agreements (RCAs). We are required to pay fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

(in millions)		Total	Outstanding	Reserved[a]	Available
2011					
Parent	**Five-year (expiring 5/3/12)[b]**	**$ 478**	**$ -**	**$ 252**	**$ 226**
PEC	**Three-year (expiring 10/15/13)**	**750**	**-**	**184**	**566**
PEF	**Three-year (expiring 10/15/13)**	**750**	**-**	**233**	**517**
Total credit facilities		**$ 1,978**	**$ -**	**$ 669**	**$ 1,309**
2010					
Parent	Five-year (expiring 5/3/12)	$ 500	$ -	$ 31	$ 469
PEC	Three-year (expiring 10/15/13)	750	-	-	750
PEF	Three-year (expiring 10/15/13)	750	-	-	750
Total credit facilities		$ 2,000	$ -	$ 31	$ 1,969

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011 and 2010, the Parent had issued $2 million and $31 million, respectively, of letters of credit supported by the RCA. Additionally, on December 31, 2011, the Parent, PEC and PEF had $250 million, $184 million and $233 million, respectively, of outstanding commercial paper supported by the RCA.

[b] On February 15, 2012, the Parent's RCA was amended to extend its expiration date to May 3, 2013.

The combined RCAs of the Parent, PEC and PEF total $1.978 billion and are supported by 23 financial institutions. The RCAs are used to provide liquidity support for issuances of commercial paper and other short-term obligations, and for general corporate purposes. Fees and interest rates under the RCAs are determined based upon the respective credit ratings of the Parent's, PEC's and PEF's long-term unsecured senior noncredit-enhanced debt, as rated by Moody's Investor Services, Inc. (Moody's) and Standard & Poor's Rating Services (S&P). The RCAs do not include material adverse change representations for borrowings or financial covenants for interest coverage.

The Parent entered into a five-year RCA on May 3, 2006. On May 2, 2008, the expiration date of the RCA was extended to May 3, 2012. The Parent ratably reduced the size of the RCA to $500 million on October 15, 2010, and the RCA was further reduced to $478 million on May 3, 2011, following the expiration of one financial institution's credit commitment. On February 15, 2012, the Parent's $478 million RCA was amended to extend the expiration date from May 3, 2012, to May 3, 2013, with its existing syndicate of 14 financial institutions.

PEC and PEF entered into $750 million, three-year RCAs with a syndication of 22 financial institutions on October 15, 2010. The RCAs, which expire October 15, 2013, replaced PEC's and PEF's previous RCAs, which were set to expire on June 28, 2011, and March 28, 2011, respectively.

See "Covenants and Default Provisions" for additional provisions related to the RCAs.

The following table summarizes short-term debt, comprised of outstanding commercial paper and other miscellaneous short-term debt, and related weighted-average interest rates at December 31:

(in millions)	2011		2010	
Parent	**0.50 %**	**$ 250**	- %	$ -
PEC	**0.49**	**188**	-	-
PEF	**0.51**	**233**	-	-
Total	**0.50 %**	**$ 671**	- %	$ -

Long-term debt maturities during the next five years are as follows:

(in millions)	Progress Energy Consolidated	PEC	PEF
2012	$ 950	$ 500	$ -
2013	830	405	425
2014	300	-	-
2015	1,000	700	300
2016	300	-	-

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 capitalization ratio (leverage). At December 31, 2011, 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 %	46 %
PEF	65 %	51 %

[a] Indebtedness as defined by the credit agreement includes certain letters of credit, surety bonds 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 by each other or by 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 $4.000 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, 2011, the Parent had no shares of preferred stock outstanding. See Note 2 for information regarding restrictions on dividends relative to the Progress Energy and Duke Energy Agreement and Plan of Merger.

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, 2011, 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, as defined by PEC's Articles of Incorporation, 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, 2011, PEC's common stock equity was approximately 57.6 percent of total capitalization. At December 31, 2011, 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, 2011, 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, as defined by PEF's Articles of Incorporation, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2011, PEF's common stock equity was approximately 50.9 percent of total capitalization. At December 31, 2011, none of PEF's cash dividends or distributions on common stock was restricted.

C. COLLATERALIZED OBLIGATIONS

PEC's and PEF's first mortgage bonds, including pollution control obligations, 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, 2011, PEC and PEF had a total of $3.694 billion and $4.341 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations.

Each mortgage allows the issuance of additional first mortgage bonds based on property additions, retirements of first mortgage bonds and the deposit of cash if certain conditions are satisfied. Most first mortgage bond issuances by PEC and PEF require that adjusted net earnings be at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. PEF's ratio of net earnings to the annual interest requirement for bonds outstanding was below 2.0 times at December 31, 2011. PEF's 2011 net earnings were impacted by a $288 million charge recorded in December 2011 for amounts to be refunded to customers (See Note 8C). Until this ratio, which is calculated based on results for 12 consecutive months, is above 2.0 times, PEF's capacity to issue first mortgage bonds is limited to a portion of retired first mortgage bonds. In the event PEF's long-term debt requirements exceed its first mortgage bond capacity, it could issue unsecured debt.

D. GUARANTEES OF SUBSIDIARY DEBT

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

E. HEDGING ACTIVITIES

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

13. INVESTMENTS

A. INVESTMENTS

At December 31, 2011 and 2010, 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)	**2011**	2010	**2011**	2010	**2011**	2010
Nuclear decommissioning trust (See Notes 5C and 14)	**$ 1,647**	$ 1,571	**$ 1,088**	$ 1,017	**$ 559**	$ 554
Equity method investments[a]	**14**	16	**1**	3	**2**	2
Cost investments[b]	**2**	5	**2**	4	**-**	-
Company-owned life insurance[c]	**47**	46	**39**	37	**-**	-
Benefit investment trusts[d]	**176**	175	**105**	97	**37**	37
Total	**$ 1,886**	$ 1,813	**$ 1,235**	$ 1,158	**$ 598**	$ 593

(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 on 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 on the Consolidated Balance Sheets.

(c) Investments in company-owned life insurance approximate fair value due to the nature of the investments and are included in miscellaneous other property and investments on the Consolidated Balance Sheets.

(d) Benefit investment trusts are included in miscellaneous other property and investments on the Consolidated Balance Sheets. At December 31, 2011 and 2010, $173 million and $166 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

Declines in fair value of available-for-sale securities to below the cost basis that are judged to be other than temporary are included in long-term regulatory assets or 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 14 for additional information. There were no material other-than-temporary impairments recognized in earnings in 2011, 2010 or 2009.

14. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.941 billion and $12.642 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $15.3 billion and $14.0 billion at December 31, 2011 and 2010, 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 5C). 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:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 1,033**	**$ 29**	**$ 401**
Preferred stock and other equity	**29**	**-**	**11**
Corporate debt	**86**	**-**	**6**
U.S. state and municipal debt	**128**	**2**	**7**
U.S. and foreign government debt	**284**	**-**	**18**
Money market funds and other	**70**	**-**	**1**
Total	**$ 1,630**	**$ 31**	**$ 444**
2010			
Common stock equity	$ 1,021	$ 13	$ 408
Preferred stock and other equity	28	-	11
Corporate debt	90	-	6
U.S. state and municipal debt	132	4	3
U.S. and foreign government debt	264	2	10
Money market funds and other	52	-	1
Total	$ 1,587	$ 19	$ 439

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 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 2011 and 2010 relate to the NDT funds. There were no material unrealized losses and unrealized gains for the other available-for-sale debt securities held in benefit trusts at December 31, 2011 and 2010.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $136 million and $195 million, respectively.

At December 31, 2011, the fair value of our available-for-sale debt securities by contractual maturity was:

(in millions)		
Due in one year or less	$	44
Due after one through five years		231
Due after five through 10 years		147
Due after 10 years		90
Total	$	512

The following table presents selected information about our 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)		**2011**	2010	2009
Proceeds	**$**	**4,640**	$ 6,747	$ 2,207
Realized gains		**30**	21	26
Realized losses		**33**	27	87

Proceeds were primarily related to NDT funds. Realized gains and losses for investments in the 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. At December 31, 2011 and 2010, 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 $4.193 billion and $3.693 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.7 billion and $4.0 billion at December 31, 2011 and 2010, 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 5C). 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:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 673**	**$ 20**	**$ 255**
Preferred stock and other equity	**17**	**-**	**7**
Corporate debt	**69**	**-**	**5**
U.S. state and municipal debt	**56**	**-**	**3**
U.S. and foreign government debt	**226**	**-**	**16**
Money market funds and other	**60**	**-**	**1**
Total	**$ 1,101**	**$ 20**	**$ 287**
2010			
Common stock equity	$ 652	$ 10	$ 256
Preferred stock and other equity	14	-	6
Corporate debt	72	-	5
U.S. state and municipal debt	51	1	1
U.S. and foreign government debt	199	1	9
Money market funds and other	42	-	1
Total	$ 1,030	$ 12	$ 278

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 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 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $98 million and $104 million, respectively.

At December 31, 2011, the fair value of PEC's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 16
Due after one through five years	184
Due after five through 10 years	100
Due after 10 years	62
Total	$ 362

The following table presents selected information about PEC'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)	2011	2010	2009
Proceeds	**$ 496**	$ 419	$ 622
Realized gains	**13**	10	9
Realized losses	**16**	19	36

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. At December 31, 2011 and 2010, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.482 billion at December 31, 2011 and 2010. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $5.4 billion and $5.0 billion at December 31, 2011 and 2010, 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. 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 5C). 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:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 360**	**$ 9**	**$ 146**
Preferred stock and other equity	**12**	**-**	**4**
Corporate debt	**17**	**-**	**1**
U.S. state and municipal debt	**72**	**2**	**4**
U.S. and foreign government debt	**58**	**-**	**2**
Money market funds and other	**10**	**-**	**-**
Total	**$ 529**	**$ 11**	**$ 157**
2010			
Common stock equity	$ 369	$ 3	$ 152
Preferred stock and other equity	14	-	5
Corporate debt	14	-	1
U.S. state and municipal debt	81	3	2
U.S. and foreign government debt	62	1	1
Money market funds and other	10	-	-
Total	$ 550	$ 7	$ 161

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 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 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $38 million and $87 million, respectively.

At December 31, 2011, the fair value of PEF's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 28
Due after one through five years	47
Due after five through 10 years	47
Due after 10 years	28
Total	$ 150

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)		2011	2010	2009
Proceeds	$	4,130	$ 6,170	$ 1,471
Realized gains		17	10	14
Realized losses		17	8	50

PEF's proceeds were 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. At December 31, 2011 and 2010, 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 in which quoted prices or other observable inputs are not available.

Certain assets and liabilities, including long-lived assets, were measured at fair value on a nonrecurring basis. There were no significant fair value measurement losses recognized for such assets and liabilities in the periods reported. These fair value measurements fall within Level 3 of the hierarchy discussed above.

The following tables set forth, by level within the fair value hierarchy, our and the Utilities' financial assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input 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
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 1,033	$ -	$ -	$ 1,033
Preferred stock and other equity	28	1	-	29
Corporate debt	-	86	-	86
U.S. state and municipal debt	-	128	-	128
U.S. and foreign government debt	87	197	-	284
Money market funds and other	-	87	-	87
Total nuclear decommissioning trust funds	1,148	499	-	1,647
Derivatives				
Commodity forward contracts	-	5	-	5
Other marketable securities				
Money market and other	20	-	-	20
Total assets	$ 1,168	$ 504	$ -	$ 1,672
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 668	$ 24	$ 692
Interest rate contracts	-	93	-	93
Contingent value obligations	-	14	-	14
Total liabilities	$ -	$ 775	$ 24	$ 799

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 1,021	$ -	$ -	$ 1,021
Preferred stock and other equity	22	6	-	28
Corporate debt	-	86	-	86
U.S. state and municipal debt	-	132	-	132
U.S. and foreign government debt	79	182	-	261
Money market funds and other	1	42	-	43
Total nuclear decommissioning trust funds	1,123	448	-	1,571
Derivatives				
Commodity forward contracts	-	15	-	15
Interest rate contracts	-	4	-	4
Other marketable securities				
Corporate debt	-	4	-	4
U.S. and foreign government debt	-	3	-	3
Money market and other	18	-	-	18
Total assets	$ 1,141	$ 474	$ -	$ 1,615
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 458	$ 36	$ 494
Interest rate contracts	-	39	-	39
Contingent value obligations	-	15	-	15
Total liabilities	$ -	$ 512	$ 36	$ 548

PEC

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 673	$ -	$ -	$ 673
Preferred stock and other equity	17	-	-	17
Corporate debt	-	69	-	69
U.S. state and municipal debt	-	56	-	56
U.S. and foreign government debt	81	145	-	226
Money market funds and other	-	47	-	47
Total nuclear decommissioning trust funds	771	317	-	1,088
Other marketable securities	6	-	-	6
Total assets	$ 777	$ 317	$ -	$ 1,094
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 177	$ 24	$ 201
Interest rate contracts	-	47	-	47
Total liabilities	$ -	$ 224	$ 24	$ 248

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 652	$ -	$ -	$ 652
Preferred stock and other equity	14	-	-	14
Corporate debt	-	72	-	72
U.S. state and municipal debt	-	51	-	51
U.S. and foreign government debt	76	123	-	199
Money market funds and other	1	28	-	29
Total nuclear decommissioning trust funds	743	274	-	1,017
Derivatives				
Commodity forward contracts	-	2	-	2
Interest rate contracts	-	3	-	3
Other marketable securities	4	-	-	4
Total assets	$ 747	$ 279	$ -	$ 1,026
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 87	$ 36	$ 123
Interest rate contracts	-	11	-	11
Total liabilities	$ -	$ 98	$ 36	$ 134

PEF

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	**$ 360**	**$ -**	**$ -**	**$ 360**
Preferred stock and other equity	**11**	**1**	**-**	**12**
Corporate debt	**-**	**17**	**-**	**17**
U.S. state and municipal debt	**-**	**72**	**-**	**72**
U.S. and foreign government debt	**6**	**52**	**-**	**58**
Money market funds and other	**-**	**40**	**-**	**40**
Total nuclear decommissioning trust funds	**377**	**182**	**-**	**559**
Derivatives				
Commodity forward contracts	**-**	**5**	**-**	**5**
Other marketable securities	**1**	**-**	**-**	**1**
Total assets	**$ 378**	**$ 187**	**$ -**	**$ 565**
Liabilities				
Derivatives				
Commodity forward contracts	**$ -**	**$ 491**	**$ -**	**$ 491**
Interest rate contracts	**-**	**8**	**-**	**8**
Total liabilities	**$ -**	**$ 499**	**$ -**	**$ 499**

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 369	$ -	$ -	$ 369
Preferred stock and other equity	8	6	-	14
Corporate debt	-	14	-	14
U.S. state and municipal debt	-	81	-	81
U.S. and foreign government debt	3	59	-	62
Money market funds and other	-	14	-	14
Total nuclear decommissioning trust funds	380	174	-	554
Derivatives				
Commodity forward contracts	-	13	-	13
Other marketable securities	1	-	-	1
Total assets	$ 381	$ 187	$ -	$ 568
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 371	$ -	$ 371
Interest rate contracts	-	7	-	7
Total liabilities	$ -	$ 378	$ -	$ 378

The determination of the fair values in the preceding tables 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 forward contract derivatives and interest rate contract derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity forward contract derivatives and interest rate contract 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 18 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.

Contingent Value Obligations (CVOs), which are derivatives, are discussed further in Note 16. At September 30, 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement (a Level 3 input) and classified CVOs as Level 3 at that date. Prior to September 30, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market and classified as Level 2. In November 2011, we commenced a public tender offer that expired on February 15, 2012. All CVOs not tendered as of December 31, 2011, were classified as Level 2 based on observable prices in the less-than-active market.

Transfers in (out) of Levels 1, 2 or 3 represent existing assets or liabilities previously categorized as a higher level for which the inputs to the estimate became less observable or assets and liabilities that were previously classified as Level 2 or 3 for which the lowest significant input became more observable during the period. There were no significant transfers in (out) of Levels 1, 2 and 3 during the period other than the CVO transfer previously discussed. Transfers into and out of each level are measured at the end of the period.

A reconciliation of changes in the fair value of our and the Utilities' derivatives, net classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

PROGRESS ENERGY

(in millions)	2011	2010	2009
Derivatives, net at beginning of period	$ **36**	$ 39	$ 41
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**21**	44	13
Repurchases of CVOs under settlement and tender offer	**(60)**	-	-
Transfers into Level 3 – CVOs	**74**	-	-
Transfers out of Level 3 – CVOs	**(14)**	-	-
Transfers in (out) of Level 3, net – commodities	**(33)**	(47)	(15)
Derivatives, net at end of period	$ **24**	$ 36	$ 39

PEC

(in millions)	2011	2010	2009
Derivatives, net at beginning of period	$ **36**	$ 27	$ 22
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**20**	27	7
Transfers in (out) of Level 3, net – commodities	**(32)**	(18)	(2)
Derivatives, net at end of period	$ **24**	$ 36	$ 27

PEF

(in millions)	2011	2010	2009
Derivatives, net at beginning of period	$ -	$ 12	$ 19
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**1**	17	6
Transfers in (out) of Level 3, net – commodities	**(1)**	(29)	(13)
Derivatives, net at end of period	$ -	$ -	$ 12

Substantially all unrealized gains and losses on the Utilities' derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Realized and unrealized losses on the change in fair value of our CVOs are discussed in Note 18.

15. 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.

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

(in millions)	2011	2010
Deferred income tax assets		
Derivative instruments	$ 309	$ 204
Income taxes refundable through future rates	375	271
Pension and other postretirement benefits	591	447
Other	522	501
Tax credit carry forwards	872	839
Net operating loss carry forwards	291	105
Valuation allowance	(71)	(60)
Total deferred income tax assets	2,889	2,307
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(3,098)	(2,439)
Income taxes recoverable through future rates	(1,271)	(875)
Other	(303)	(386)
Total deferred income tax liabilities	(4,672)	(3,700)
Total net deferred income tax liabilities	$ (1,783)	$ (1,393)

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

(in millions)	2011	2010
Current deferred income tax assets, included in deferred tax assets	$ 371	$ 156
Noncurrent deferred income tax assets, included in other assets and deferred debits	27	34
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(2,181)	(1,583)
Total net deferred income tax liabilities	$ (1,783)	$ (1,393)

At December 31, 2011, we had the following tax credit and net operating loss carry forwards:

- $868 million of federal alternative minimum tax credits that do not expire.
- $4 million of federal general business credits that will expire during the period 2028 through 2031.
- $623 million of gross federal net operating loss carry forwards that will expire during 2031. $14 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1.9 billion of gross state net operating loss carry forwards that will expire during the period 2012 through 2031.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of $11 million in our deferred income tax assets and valuation allowances during 2011 related to prior year state net operating loss carry forwards at Progress Fuels Corporation.

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.

Certain substantial changes in ownership of Progress Energy, including the proposed merger between Progress Energy and Duke Energy (See Note 2), can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards.

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

	2011	2010	2009
Effective income tax rate	**35.6 %**	38.3 %	32.1 %
State income taxes, net of federal benefit	**(4.3)**	(4.3)	(3.7)
Investment tax credit amortization	**0.8**	0.5	0.8
Employee stock ownership plan dividends	**1.4**	0.9	1.0
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**2.6**	1.4	2.2
Other differences, net	**(1.1)**	(1.8)	1.8
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)	2011	2010	2009
Current			
Federal	**$ (91)**	$ (46)	$ 227
State	**29**	(13)	41
Total current income tax expense (benefit)	**(62)**	(59)	268
Deferred			
Federal	**578**	542	114
State	**27**	100	25
Total deferred income tax expense	**605**	642	139
Investment tax credit	**(7)**	(7)	(10)
Net operating loss carry forward	**(213)**	(37)	-
Total income tax expense	**$ 323**	$ 539	$ 397

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

- Taxes related to discontinued operations recorded net of tax for 2011, 2010 and 2009, which are presented separately in Note 4A.
- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, 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 2011 and 2009.

At December 31, 2011, 2010 and 2009, our liability for unrecognized tax benefits was $173 million, $176 million and $160 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $6 million, $8 million and $9 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	2011	2010	2009
Unrecognized tax benefits at beginning of period	$ 176	$ 160	$ 104
Gross amounts of increases as a result of tax positions taken in a prior period	88	10	11
Gross amounts of decreases as a result of tax positions taken in a prior period	(24)	(4)	(3)
Gross amounts of increases as a result of tax positions taken in the current period	9	14	52
Gross amounts of decreases as a result of tax positions taken in the current period	(8)	(4)	(4)
Amounts of net decreases relating to settlements with taxing authorities	(68)	-	-
Unrecognized tax benefits at end of period	$ 173	$ 176	$ 160

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our federal tax years are open for examination from 2007 forward, and our open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $25 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the net interest (benefit) expense related to unrecognized tax benefits was $(24) million, $9 million and $9 million, respectively, of which a respective $(22) million, $5 million and $5 million (benefit) 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 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009, we accrued $21 million, $45 million and $36 million, respectively, for interest and penalties, which were 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)	2011	2010
Deferred income tax assets		
ARO liability	$ 101	$ 103
Derivative instruments	96	49
Income taxes refundable through future rates	142	142
Pension and other postretirement benefits	244	180
Other	168	158
Tax credit carry forwards	3	-
Net operating loss carry forwards	54	-
Total deferred income tax assets	808	632
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,908)	(1,552)
Income taxes recoverable through future rates	(541)	(421)
Investments	(103)	(104)
Other	(17)	(35)
Total deferred income tax liabilities	(2,569)	(2,112)
Total net deferred income tax liabilities	$ (1,761)	$ (1,480)

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

(in millions)	2011	2010
Current deferred income tax assets, included in deferred tax assets	$ 142	$ 65
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(1,903)	(1,545)
Total net deferred income tax liabilities	$ (1,761)	$ (1,480)

At December 31, 2011, PEC had the following tax credit and net operating loss carry forwards:

- $3 million of federal general business credits that will expire during the period 2028 through 2031.
- $161 million of gross federal net operating loss carry forwards that will expire during 2031. $6 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1 million of gross state net operating loss carry forwards that will expire during the period 2012 through 2030.

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

	2011	2010	2009
Effective income tax rate	33.2 %	36.8 %	35.0 %
State income taxes, net of federal benefit	(2.3)	(3.2)	(2.8)
Investment tax credit amortization	0.7	0.6	0.7
Domestic manufacturing deduction	-	0.4	0.9
AFUDC equity	2.2	1.5	0.6
Other differences, net	1.2	(1.1)	0.6
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)	2011	2010	2009
Current			
Federal	$ (27)	$ 73	$ 192
State	21	(8)	21
Total current income tax expense (benefit)	(6)	65	213
Deferred			
Federal	316	238	57
State	6	53	13
Total deferred income tax expense	322	291	70
Investment tax credit	(6)	(6)	(6)
Net operating loss carry forward	(54)	-	-
Total income tax expense	$ 256	$ 350	$ 277

Total income tax expense excluded taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.

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 $4 million and $78 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEC's liability for unrecognized tax benefits was $73 million, $74 million and $59 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $4 million and $5 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	2011	2010	2009
Unrecognized tax benefits at beginning of period	$ 74	$ 59	$ 38
Gross amounts of increases as a result of tax positions taken in a prior period	19	8	6
Gross amounts of decreases as a result of tax positions taken in a prior period	(14)	(2)	(2)
Gross amounts of increases as a result of tax positions taken in the current period	8	10	17
Gross amounts of decreases as a result of tax positions taken in the current period	(4)	(1)	-
Amounts of net decreases relating to settlements with taxing authorities	(10)	-	-
Unrecognized tax benefits at end of period	$ 73	$ 74	$ 59

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 2007 forward, and PEC's open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. 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, 2012.

PEC includes interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the interest (benefit) expense recorded related to unrecognized tax benefits was $(6) million, $4 million and $3 million, respectively. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009,

we accrued $8 million, $14 million and $10 million, respectively, for interest and penalties, which were 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)	2011	2010
Deferred income tax assets		
Derivative instruments	$ 198	$ 145
Income taxes refundable through future rates	198	93
Pension and other postretirement benefits	224	170
Reserve for storm damage	52	52
Unbilled revenue	39	61
Other	101	82
Tax credit carry forwards	1	3
Net operating loss carry forwards	41	9
Total deferred income tax assets	854	615
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,180)	(874)
Deferred fuel recovery	(40)	(65)
Deferred nuclear cost recovery	(68)	(94)
Income taxes recoverable through future rates	(685)	(454)
Investments	(56)	(60)
Other	(12)	(18)
Total deferred income tax liabilities	(2,041)	(1,565)
Total net deferred income tax liabilities	$ (1,187)	$ (950)

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

(in millions)	2011	2010
Current deferred income tax assets, included in deferred tax assets	$ 138	$ 77
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(1,325)	(1,027)
Total net deferred income tax liabilities	$ (1,187)	$ (950)

At December 31, 2011, PEF had the following tax credit and net operating loss carry forwards:

- $1 million of federal general business credits that will expire during the period 2029 through 2031.
- $120 million of gross federal net operating loss carry forwards that will expire during 2031. $3 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.

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

	2011	2010	2009
Effective income tax rate	**36.3 %**	37.9 %	31.1 %
State income taxes, net of federal benefit	**(3.5)**	(3.2)	(3.0)
Investment tax credit amortization	**0.3**	0.2	0.7
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**1.4**	0.8	3.4
Other differences, net	**0.5**	(0.7)	2.0
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)	2011	2010	2009
Current			
Federal	**$ (60)**	$ (44)	$ 125
State	**5**	(4)	20
Total current income tax expense (benefit)	**(55)**	(48)	145
Deferred			
Federal	**255**	293	57
State	**22**	41	11
Total deferred income tax expense	**277**	334	68
Investment tax credit	**(1)**	(1)	(4)
Net operating loss carry forward	**(41)**	(9)	-
Total income tax expense	**$ 180**	$ 276	$ 209

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, 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 2011 and 2009.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $23 million and $71 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEF's liability for unrecognized tax benefits was $80 million, $99 million and $98 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $2 million and $3 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	2011	2010	2009
Unrecognized tax benefits at beginning of period	$ 99	$ 98	$ 62
Gross amounts of increases as a result of tax positions taken in a prior period	66	2	5
Gross amounts of decreases as a result of tax positions taken in a prior period	(21)	(1)	(1)
Gross amounts of increases as a result of tax positions taken in the current period	1	3	35
Gross amounts of decreases as a result of tax positions taken in the current period	(4)	(3)	(3)
Amounts of net decreases relating to settlements with taxing authorities	(61)	-	-
Unrecognized tax benefits at end of period	$ 80	$ 99	$ 98

We file consolidated federal and state income tax returns that include PEF. PEF's open federal tax years are from 2007 forward, and PEF's open state tax years generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $20 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our 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 net interest charges on the Statements of Income. Penalties are included in other, net on the Statements of Income. During 2011, 2010 and 2009, interest (benefit) expense recorded as a regulatory asset was $(22) million, $5 million and $5 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. During 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. At December 31, 2011, 2010 and 2009, PEF accrued $7 million, $29 million and $24 million, respectively, for interest and penalties, which were included in prepayments and other current assets and other liabilities and deferred credits on the Balance Sheets.

16. 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, three of which 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 4A). The payments are based on the net after-tax cash flows the facilities generated. We 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. The balance of the CVO trust at December 31, 2011 and 2010, was $11 million and is included in other assets and deferred debits on the Consolidated Balance Sheets. Future payments from the trust to CVO holders will not be made until certain conditions are satisfied and will include principal and interest earned during the investment period net of expenses deducted. Interest earned on the payments held in trust for 2011 and 2010 was insignificant.

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us (see Note 22D) related to their ownership of CVOs. On October 3, 2011, we entered a settlement agreement and release with Davidson Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. In November 2011, we also

commenced a tender offer for all remaining outstanding CVOs at the same purchase price. The tender offer expired on February 15, 2012, and as a result, 83.4 million CVOs were repurchased through the settlement agreement or through the tender offer. The CVOs are derivatives and are recorded at fair value. At September 30, 2011, the purchase price included in the settlement agreement and subsequent tender offer represented the fair value of the CVOs. Prior to September 30, 2011, and at December 31, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market (see Note 14). A pre-tax loss of $59 million from the changes in fair value during 2011 is recorded in other, net on the Consolidated Statements of Income. At December 31, 2011, the CVO liability included in other current liabilities on our Consolidated Balance Sheets was $14 million based on the 18.5 million outstanding CVOs not held by the Parent. At December 31, 2010, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million based on the 98.6 million CVOs outstanding.

17. 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 the years ended December 31. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

PROGRESS ENERGY

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 53**	$ 48	$ 42	**$ 11**	$ 16	$ 7
Interest cost	**141**	140	138	**41**	45	31
Expected return on plan assets	**(182)**	(157)	(133)	**(2)**	(4)	(4)
Amortization of actuarial loss[a]	**69**	51	54	**12**	13	1
Other amortization, net [a]	**7**	6	6	**5**	5	5
Net periodic cost before deferral[b]	**$ 88**	$ 88	$ 107	**$ 67**	$ 75	$ 40

[a] Adjusted to reflect PEF's rate treatment (See Note 17B).

[b] PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

PEC

(in millions)	Pension Benefits			OPEB		
	2011	2010	2009	**2011**	2010	2009
Service cost	**$ 21**	$ 19	$ 18	**$ 5**	$ 5	$ 5
Interest cost	**63**	64	64	**20**	20	16
Expected return on plan assets	**(91)**	(77)	(67)	**-**	(2)	(2)
Amortization of actuarial loss	**26**	16	11	**5**	4	-
Other amortization, net	**5**	6	6	**1**	1	1
Net periodic cost	**$ 24**	$ 28	$ 32	**$ 31**	$ 28	$ 20

PEF

(in millions)	Pension Benefits			OPEB		
	2011	2010	2009	**2011**	2010	2009
Service cost	**$ 25**	$ 22	$ 19	**$ 5**	$ 10	$ 2
Interest cost	**59**	59	56	**18**	22	13
Expected return on plan assets	**(78)**	(68)	(56)	**(2)**	(2)	(1)
Amortization of actuarial loss	**33**	31	38	**7**	9	-
Other amortization, net	**-**	-	-	**4**	4	3
Net periodic cost before deferral[a]	**$ 39**	$ 44	$ 57	**$ 32**	$ 43	$ 17

[a] PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

The following tables provide a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income for 2011, 2010 and 2009. The tables also include comparable items that affected regulatory assets. 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

(in millions)	Pension Benefits			OPEB		
	2011	2010	2009	**2011**	2010	2009
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$ (20)**	$ (11)	$ (1)	**$ (2)**	$ (10)	$ 4
Regulatory asset adjustment	**84**	-	-	**(4)**	-	-
Reclassification adjustments						
Net actuarial loss	**10**	4	5	**-**	-	1
Other, net	**2**	-	-	**-**	-	1
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**(307)**	(65)	10	**(95)**	(164)	64
Reclassification adjustment	**(84)**	-	-	**4**	-	-
Other, net	**-**	-	(3)	**-**	-	-
Amortized to income[a]						
Net actuarial loss	**59**	47	49	**12**	13	-
Other, net	**5**	6	6	**5**	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

(in millions)	Pension Benefits 2011	2010	2009	OPEB 2011	2010	2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	$ **(134)**	$ (24)	$ (14)	$ **(49)**	$ (64)	$ 38
Other, net	**-**	-	(2)	**-**	-	-
Amortized to income						
Net actuarial loss	**26**	16	11	**5**	4	-
Other, net	**5**	6	6	**1**	1	1

PEF

(in millions)	Pension Benefits 2011	2010	2009	OPEB 2011	2010	2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	$ **(147)**	$ (41)	$ 24	$ **(39)**	$ (100)	$ 26
Other, net	**-**	-	(1)	**-**	-	-
Amortized to income[(a)]						
Net actuarial loss	**33**	31	38	**7**	9	-
Other, net	**-**	-	-	**4**	4	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 2011	2010	2009	OPEB 2011	2010	2009
Discount rate	**5.60 %**	6.00 %	6.30 %	**5.70 %**	6.05 %	6.20 %
Rate of increase in future compensation						
Bargaining	**4.50 %**	4.50 %	4.25 %	-	-	-
Supplementary plans	**5.25 %**	5.25 %	5.25 %	-	-	-
Expected long-term rate of return on plan assets	**8.50 %**	8.75 %	8.75 %	**5.00 %**	6.60 %	6.80 %

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% for 2010 and 2009. PEC held no OPEB plan assets during 2011.

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 2011, primarily due to a shift in our investment strategy. 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, 2011 and 2010 are presented in the tables below, with each table followed by related supplementary information.

PROGRESS ENERGY

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Projected benefit obligation at January 1	**$ 2,609**	$ 2,422	**$ 733**	$ 543
Service cost	**53**	48	**11**	16
Interest cost	**141**	140	**41**	45
Settlements	**(6)**	-	**-**	-
Benefit payments	**(129)**	(129)	**(42)**	(44)
Plan amendment	**-**	1	**-**	-
Actuarial loss	**238**	127	**98**	173
Obligation at December 31	**2,906**	2,609	**841**	733
Fair value of plan assets at December 31	**2,191**	1,891	**37**	33
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.906 billion and $2.609 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $2.854 billion and $2.563 billion at December 31, 2011 and 2010, respectively, and plan assets of $2.191 billion and $1.891 billion at December 31, 2011 and 2010, respectively.

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

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Current liabilities	**$ (10)**	$ (10)	**$ (22)**	$ (22)
Noncurrent liabilities	**(705)**	(708)	**(782)**	(678)
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$ 34**	$ 90	**$ -**	$ 5
Other, net	**2**	9	**-**	1
Recognized in regulatory assets, net				
Net actuarial loss	**1,139**	824	**274**	183
Other, net	**56**	55	**3**	9
Total not yet recognized as a component of net periodic cost[(a)]	**$ 1,231**	$ 978	**$ 277**	$ 198

(a) All components are adjusted to reflect PEF's rate treatment (See Note 17B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss[(a)]	$ 91	$ 23
Amortization of other, net[(a)]	9	4

(a) Adjusted to reflect PEF's rate treatment (See Note 17B).

PEC

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Projected benefit obligation at January 1	**$ 1,188**	$ 1,120	**$ 352**	$ 282
Service cost	**21**	19	**5**	5
Interest cost	**63**	64	**20**	20
Benefit payments	**(56)**	(56)	**(19)**	(19)
Actuarial loss	**86**	41	**49**	64
Obligation at December 31	**1,302**	1,188	**407**	352
Fair value of plan assets at December 31	**1,091**	884	**-**	-
Funded status	**$ (211)**	$ (304)	**$ (407)**	$ (352)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.302 billion and $1.188 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.297 billion and $1.184 billion at December 31, 2011 and 2010, respectively, and plan assets of $1.091 billion and $884 million at December 31, 2011 and 2010, respectively.

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

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Current liabilities	**$ (2)**	$ (2)	**$ (19)**	$ (19)
Noncurrent liabilities	**(209)**	(302)	**(388)**	(333)
Funded status	**$ (211)**	$ (304)	**$ (407)**	$ (352)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Recognized in regulatory assets				
Net actuarial loss	**$ 527**	$ 418	**$ 121**	$ 76
Other, net	**43**	49	**-**	2
Total not yet recognized as a component of net periodic cost	**$ 570**	$ 467	**$ 121**	$ 78

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss	$ 37	$ 11
Amortization of other, net	8	-

PEF

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Projected benefit obligation at January 1	**$ 1,087**	$ 992	**$ 326**	$ 219
Service cost	**25**	22	**5**	10
Interest cost	**59**	59	**18**	22
Plan amendment	**-**	1	**-**	-
Benefit payments	**(58)**	(58)	**(21)**	(23)
Actuarial loss	**110**	71	**40**	98
Obligation at December 31	**1,223**	1,087	**368**	326
Fair value of plan assets at December 31	**969**	871	**37**	33
Funded status	**$ (254)**	$ (216)	**$ (331)**	$ (293)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.223 billion and $1.087 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.184 billion and $1.049 billion at December 31, 2011 and 2010, respectively, and plan assets of $969 million and $871 million at December 31, 2011 and 2010, respectively.

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

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Current liabilities	**$ (3)**	$ (3)	**$ -**	$ -
Noncurrent liabilities	**(251)**	(213)	**(331)**	(293)
Funded status	**$ (254)**	$ (216)	**$ (331)**	$ (293)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31.

(in millions)	Pension Benefits 2011	Pension Benefits 2010	OPEB 2011	OPEB 2010
Recognized in regulatory assets, net				
Net actuarial loss	**$ 520**	$ 406	**$ 139**	$ 107
Other, net	**6**	6	**3**	7
Total not yet recognized as a component of net periodic cost	**$ 526**	$ 412	**$ 142**	$ 114

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss	$ 45	$ 12
Amortization of other, net	-	3

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

	Pension Benefits		OPEB	
	2011	2010	**2011**	2010
Discount rate	**4.75 %**	5.65 %	**4.85 %**	5.75 %
Rate of increase in future compensation				
Bargaining	**4.00 %**	4.50 %	-	-
Supplementary plans	**5.25 %**	5.25 %	-	-
Initial medical cost trend rate for pre-Medicare Act benefits	-	-	**8.75 %**	8.50 %
Initial medical cost trend rate for post-Medicare Act benefits	-	-	**8.75 %**	8.50 %
Ultimate medical cost trend rate	-	-	**5.00 %**	5.00 %
Year ultimate medical cost trend rate is achieved	-	-	**2020**	2017

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.

	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			
Effect on total of service and interest cost	$ 3	$ 1	$ 1
Effect on postretirement benefit obligation	43	21	19
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(31)	(15)	(14)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions to qualified plans for 2011 include contributions directly to pension plan assets of $334 million, $217 million and $112 million, respectively, and for 2010 include contributions directly to pension plan assets of $129 million, $95 million and $34 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 16 percent of gross benefit payments for Progress Energy, 21 percent for PEC and 12 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2011, the subsidies totaled $5 million for us, $2 million for PEC and $2 million for PEF. In 2010, 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		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 1,891**	$ 1,673	**$ 33**	$ 55
Actual return on plan assets	**91**	208	**3**	2
Benefit payments, including settlements	**(135)**	(129)	**(42)**	(44)
Employer contributions	**344**	139	**43**	20
Fair value of plan assets at December 31	**$ 2,191**	$ 1,891	**$ 37**	$ 33

PEC

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 884**	$ 749	**$ -**	$ 21
Actual return on plan assets	**44**	94	**-**	2
Benefit payments	**(56)**	(56)	**(19)**	(19)
Employer contributions (reimbursements)	**219**	97	**19**	(4)
Fair value of plan assets at December 31	**$ 1,091**	$ 884	**$ -**	$ -

PEF

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 871**	$ 794	**$ 33**	$ 32
Actual return on plan assets	**41**	98	**4**	1
Benefit payments	**(58)**	(58)	**(21)**	(23)
Employer contributions	**115**	37	**21**	23
Fair value of plan assets at December 31	**$ 969**	$ 871	**$ 37**	$ 33

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 rate of return significantly in excess of the discount rate used to measure the plan liabilities over the long term. As of December 31, 2011, the target pension asset allocations are 29 percent domestic equity, 19 percent international equity, 35 percent domestic fixed income, 10 percent private equity and timber and 7 percent absolute return 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 and includes both long only and long/short equity managers. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth-based investment strategies and includes both long only and long/short equity managers. Domestic fixed income primarily includes domestic investment grade long duration fixed income investments. 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 our pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	**$ 82**	**$ 33**	**$ -**	**$ 115**
International equity securities	**47**	**-**	**-**	**47**
Domestic equity securities	**266**	**-**	**-**	**266**
Private equity securities	**-**	**-**	**153**	**153**
Corporate bonds	**-**	**407**	**-**	**407**
U.S. state and municipal debt	**-**	**42**	**-**	**42**
U.S. and foreign government debt	**247**	**102**	**-**	**349**
Commingled funds	**-**	**490**	**-**	**490**
Hedge funds	**-**	**159**	**147**	**306**
Timber investments	**-**	**-**	**11**	**11**
Other investments	**-**	**5**	**-**	**5**
Fair value of plan assets	**$ 642**	**$ 1,238**	**$ 311**	**$ 2,191**

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2010				
Assets				
Cash and cash equivalents	$ -	$ 94	$ -	$ 94
International equity securities	40	-	-	40
Domestic equity securities	286	-	-	286
Private equity securities	-	-	147	147
Corporate bonds	-	216	-	216
U.S. state and municipal debt	-	19	-	19
U.S. and foreign government debt	144	30	-	174
Commingled funds	-	847	-	847
Hedge funds	-	51	2	53
Timber investments	-	-	11	11
Other investments	-	4	-	4
Fair value of plan assets	$ 470	$ 1,261	$ 160	$ 1,891

Our other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011, and December 31, 2010, respectively.

A reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	**$ 147**	**$ 2**	**$ 11**	**$ 160**
Net realized and unrealized gains [a]	**-**	**4**	**1**	**5**
Transfers in	**-**	**52**	**-**	**52**
Purchases, sales and distributions, net	**6**	**89**	**(1)**	**94**
Balance at December 31	**$ 153**	**$ 147**	**$ 11**	**$ 311**

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 122	$ 2	$ 14	$ 138
Net realized and unrealized gains (losses)[a]	7	-	(2)	5
Purchases, sales and distributions, net	18	-	(1)	17
Balance at December 31	$ 147	$ 2	$ 11	$ 160

[a] Substantially all amounts relate to investments held at December 31.

PEC

The following table sets forth by level within the fair value hierarchy PEC's pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	**$ 41**	**$ 16**	**$ -**	**$ 57**
International equity securities	**24**	**-**	**-**	**24**
Domestic equity securities	**133**	**-**	**-**	**133**
Private equity securities	**-**	**-**	**76**	**76**
Corporate bonds	**-**	**203**	**-**	**203**
U.S. state and municipal debt	**-**	**21**	**-**	**21**
U.S. and foreign government debt	**123**	**51**	**-**	**174**
Commingled funds	**-**	**244**	**-**	**244**
Hedge funds	**-**	**79**	**73**	**152**
Timber investments	**-**	**-**	**5**	**5**
Other investments	**-**	**2**	**-**	**2**
Fair value of plan assets	**$ 321**	**$ 616**	**$ 154**	**$ 1,091**

(in millions)	Pension Benefit Plan Assets			
	Level 1	Level 2	Level 3	Total
2010				
Assets				
Cash and cash equivalents	$ -	$ 44	$ -	$ 44
International equity securities	19	-	-	19
Domestic equity securities	134	-	-	134
Private equity securities	-	-	69	69
Corporate bonds	-	101	-	101
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	67	14	-	81
Commingled funds	-	396	-	396
Hedge funds	-	24	1	25
Timber investments	-	-	5	5
Other investments	-	1	-	1
Fair value of plan assets	$ 220	$ 589	$ 75	$ 884

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 years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	**$ 69**	**$ 1**	**$ 5**	**$ 75**
Net realized and unrealized gains[a]	**-**	**2**	**-**	**2**
Transfers in	**-**	**26**	**-**	**26**
Purchases, sales and distributions, net	**7**	**44**	**-**	**51**
Balance at December 31	**$ 76**	**$ 73**	**$ 5**	**$ 154**

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 55	$ 1	$ 6	$ 62
Net realized and unrealized gains (losses)[a]	4	-	(1)	3
Purchases, sales and distributions, net	10	-	-	10
Balance at December 31	$ 69	$ 1	$ 5	$ 75

[a] Substantially all amounts relate to investments held at December 31.

PEF

The following table sets forth by level within the fair value hierarchy PEF's pension assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
2011				
Assets				
Cash and cash equivalents	$ 36	$ 15	$ -	$ 51
International equity securities	21	-	-	21
Domestic equity securities	117	-	-	117
Private equity securities	-	-	68	68
Corporate bonds	-	180	-	180
U.S. state and municipal debt	-	19	-	19
U.S. and foreign government debt	109	45	-	154
Commingled funds	-	217	-	217
Hedge funds	-	70	65	135
Timber investments	-	-	5	5
Other investments	-	2	-	2
Fair value of plan assets	$ 283	$ 548	$ 138	$ 969

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Cash and cash equivalents	$ -	$ 43	$ -	$ 43
International equity securities	18	-	-	18
Domestic equity securities	132	-	-	132
Private equity securities	-	-	68	68
Corporate bonds	-	99	-	99
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	66	14	-	80
Commingled funds	-	391	-	391
Hedge funds	-	23	1	24
Timber investments	-	-	5	5
Other investments	-	2	-	2
Fair value of plan assets	$ 216	$ 581	$ 74	$ 871

PEF's other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011 and 2010, respectively.

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 years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	$ 68	$ 1	$ 5	$ 74
Net realized and unrealized gains[a]	-	2	-	2
Transfers in	-	23	-	23
Purchases, sales and distributions, net	-	39	-	39
Balance at December 31	$ 68	$ 65	$ 5	$ 138

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 58	$ 1	$ 7	$ 66
Net realized and unrealized gains (losses)[a]	3	-	(1)	2
Purchases, sales and distributions, net	7	-	(1)	6
Balance at December 31	$ 68	$ 1	$ 5	$ 74

[a] Substantially all amounts relate to investments held at December 31.

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.

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.

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.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2012, we expect to make contributions of $125 million-$225 million 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $182, $185, $193, $198, $200 and $1,046, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $47, $50, $53, $56, $58 and $318, 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $4, $5, $5, $6, $7 and $44, respectively.

In 2012, PEC expects to make contributions of $60 million-$110 million directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $94, $94, $99, $99, $97 and $479, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $21, $23, $25, $26, $28 and $158, 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $3, $3, $3 and $23, respectively.

In 2012, PEF expects to make contributions of $65 million-$115 million 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $64, $67, $70, $73, $76 and $430, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $23, $24, $25, $25, $26 and $137, 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 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $2, $3, $3 and $17, respectively.

The Patient Protection and Affordable Care Act (PPACA) and the related Health Care and Education Reconciliation Act, which made various amendments to the PPACA, were enacted in March 2010. The PPACA contains a provision that changes the tax treatment related to a federal subsidy available to sponsors of retiree health benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy. Employers are not currently taxed on the Retiree Drug Subsidy payments they receive. However, as a result of the PPACA as amended, Retiree Drug Subsidy payments will effectively become taxable in tax years beginning after December 31, 2012, by requiring the amount of the subsidy received to be offset against the employer's deduction for health care expenses. Under GAAP, changes in tax law are accounted for in the period of enactment. Accordingly, an additional tax expense of $22 million for us, including $12 million for PEC and $10 million for PEF, was recognized during the year ended December 31, 2010.

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 17A is adjusted as appropriate to reflect PEF's rate treatment.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVE TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit 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.

See Note 14B for information about the fair value of derivatives.

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.

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 financial derivative instruments with settlement dates 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 2012 and 2013. 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 8A). 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 posted or held cash collateral in support of these instruments. Progress Energy had a cash collateral asset included in derivative collateral posted of $147 million and $164 million on the Progress Energy Consolidated Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, Progress Energy had 380.0 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

PEC had a cash collateral asset included in prepayments and other current assets of $24 million on the PEC Consolidated Balance Sheets at December 31, 2011 and 2010. At December 31, 2011, PEC had 111.4 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases.

PEF's cash collateral asset included in derivative collateral posted was $123 million and $140 million on the PEF Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, PEF had 268.6 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

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, 2011, all open interest rate hedges will reach their mandatory termination dates within two years. At December 31, 2011, including amounts related to terminated hedges, we had $141 million of after-tax losses,

including $71 million and $25 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive loss related to forward starting swaps. It is expected that in the next 12 months losses of $12 million, net of tax, primarily related to terminated hedges, will be reclassified to interest expense at Progress Energy, including $6 million and $2 million at PEC and PEF, respectively. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of changes in interest rates, changes in 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, 2010, including amounts related to terminated hedges, we had $63 million of after-tax losses, including $33 million and $4 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive income related to forward starting swaps.

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 forward starting swaps.

At December 31, 2011, Progress Energy had $500 million notional of open forward starting swaps, including $250 million at PEC and $50 million at PEF.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million at PEC and $200 million 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, 2011 and 2010, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our commodity 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 Moody's, S&P and/or Fitch Ratings (Fitch). 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 commodity derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from Moody's, S&P and/or Fitch. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the commodity derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on commodity derivative instruments in net liability positions.

The aggregate fair value of all commodity derivative instruments at Progress Energy with credit risk-related contingent features that are in a net liability position was $489 million at December 31, 2011, for which Progress Energy has posted collateral of $147 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, Progress Energy would have been required to post an additional $342 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEC with credit risk-related contingent features that are in a liability position was $152 million at December 31, 2011, for which PEC has posted collateral of $24 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, PEC would have been required to post an additional $128 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEF with credit risk-related contingent features that are in a net liability position was $337 million at December 31, 2011, for which PEF has posted collateral of

$123 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered on December 31, 2011, PEF would have been required to post an additional $214 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

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The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	2011		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$ 2**		$ -
Derivative liabilities, long-term		**1**		-
Interest rate derivatives				
Prepayments and other current assets	**$ -**		$ 1	
Other assets and deferred debits	**-**		3	
Derivative liabilities, current		**76**		32
Derivative liabilities, long-term		**17**		7
Total derivatives designated as hedging instruments	**-**	**96**	4	39
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**5**		11	
Other assets and deferred debits	**-**		4	
Derivative liabilities, current		**357**		226
Derivative liabilities, long-term		**332**		268
CVOs[b]				
Other current liabilities		**14**		-
Other liabilities and deferred credits		**-**		15
Fair value of derivatives not designated as hedging instruments	**5**	**703**	15	509
Fair value loss transition adjustment[c]				
Derivative liabilities, current		**1**		1
Derivative liabilities, long-term		**2**		3
Total derivatives not designated as hedging instruments	**5**	**706**	15	513
Total derivatives	**$ 5**	**$ 802**	$ 19	$ 552

[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. In 2011, we purchased 80.1 million CVOs in a negotiated settlement agreement and subsequent tender offer. (See Note 16)

[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 contracts.

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:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[c]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[d] [e]	**(85)**	(34)	15	**(8)**	(6)	(6)	**(3)**	3	(3)
Total	**$ (87)**	$ (34)	$ 16	**$ (8)**	$ (6)	$ (6)	**$ (3)**	$ 3	$ (3)

[a] Effective portion.

[b] Related to ineffective portion and amount excluded from effectiveness testing.

[c] Amounts recorded on the Consolidated Statements of Income are classified in fuel used in electric generation.

[d] Amounts in accumulated OCI 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.

[e] Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
	2011	2010	2009	**2011**	2010	2009
Commodity derivatives[a]	**$ (297)**	$ (324)	$ (659)	**$ (502)**	$ (398)	$ (387)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.

[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives		
	2011	2010	2009
Commodity derivatives[a]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[a]	**1**	1	2
CVOs[a]	**(59)**	-	19
Total	**$ (58)**	$ 1	$ 22

[a] Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEC

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	2011		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Other assets and deferred debits	**$ -**		$ 3	
Derivative liabilities, current		**$ 38**		$ 7
Other liabilities and deferred credits		**9**		4
Total derivatives designated as hedging instruments	**-**	**47**	3	11
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**-**		1	
Other assets and deferred debits	**-**		1	
Derivative liabilities, current		**91**		45
Other liabilities and deferred credits		**110**		78
Fair value of derivatives not designated as hedging instruments	**-**	**201**	2	123
Fair value loss transition adjustment[b]				
Derivative liabilities, current		**1**		1
Other liabilities and deferred credits		**2**		3
Total derivatives not designated as hedging instruments	**-**	**204**	2	127
Total derivatives	**$ -**	**$ 251**	$ 5	$ 138

[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 contracts.

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:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Interest rate derivatives[c][d]	**$ (43)**	$ (10)	$ 5	**$ (5)**	$ (4)	$ (3)	**$ (1)**	$ -	$ (2)

[a] Effective portion.

[b] Related to ineffective portion and amount excluded from effectiveness testing.

[c] Amounts in accumulated OCI 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.

[d] Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments						
Instrument	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (60)**	$ (46)	$ (76)	**$ (140)**	$ (77)	$ (68)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.

[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument	Amount of Gain or (Loss) Recognized in Income on Derivatives		
(in millions)	**2011**	2010	2009
Commodity derivatives[a]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[a]	**1**	1	2
Total	**$ 1**	$ 1	$ 3

[a] Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEF

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	**2011**		2010	
(in millions)	**Asset**	**Liability**	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$ 2**		$ -
Derivative liabilities, long-term		**1**		-
Interest rate derivatives				
Derivative liabilities, current		**-**		7
Derivative liabilities, long-term		**8**		-
Total derivatives designated as hedging instruments		**11**		7
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**$ 5**		$ 10	
Other assets and deferred debits	**-**		3	
Derivative liabilities, current		**266**		181
Derivative liabilities, long-term		**222**		190
Total derivatives not designated as hedging instruments	**5**	**488**	13	371
Total derivatives	**$ 5**	**$ 499**	$ 13	$ 378

[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:

Derivatives Designated as Hedging Instruments

Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[c]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[d][e]	**(21)**	(7)	3	**-**	-	-	**-**	-	-
Total	**$ (23)**	$ (7)	$ 4	**$ -**	$ -	$ -	**$ -**	$ -	$ -

[a] Effective portion.

[b] Related to ineffective portion and amount excluded from effectiveness testing.

[c] Amounts recorded on the Statements of Income are classified in fuel used in electric generation.

[d] Amounts in accumulated OCI 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.

[e] Amounts recorded on the Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (237)**	$ (278)	$ (583)	**$ (362)**	$ (321)	$ (319)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.

[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

19. RELATED PARTY TRANSACTIONS

There were no material related party transactions in which we or any of our subsidiaries were or will be a participant and in which any of our directors, executive officers or any of their immediate family members had a direct or indirect material interest. Transactions between affiliated companies are further discussed below.

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, 2011, the Parent had issued $453 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 on the Consolidated Balance Sheets.

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 goods and services under the approved agreements. Goods and services provided by PESC during 2011, 2010 and 2009 to PEC amounted to $203 million, $176 million and $170 million, respectively, and services provided to PEF were $160 million, $156 million and $147 million, respectively. During 2010, PESC transferred a $24 million combustion turbine to PEC at cost.

PEC and PEF also provide and receive goods and services at cost. Goods and services provided by PEC to PEF during 2011, 2010 and 2009 amounted to $57 million, $43 million and $36 million, respectively. Goods and services provided by PEF to PEC during 2011, 2010 and 2009 amounted to $12 million, $18 million and $12 million, respectively.

PEC and PEF participate in an internal money pool, administered by PESC, 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 0.32%, 0.30% and 0.74% for the years ended December 31, 2011, 2010 and 2009, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded minimal interest expense related to the money pool for all the years presented.

PEC and each of its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 15).

20. 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.

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Total
At and for the year ended December 31, 2011					
Revenues					
Unaffiliated	$ 4,528	$ 4,367	$ 12	$ -	$ 8,907
Intersegment	-	2	272	(274)	-
Total revenues	4,528	4,369	284	(274)	8,907
Depreciation, amortization and accretion	514	169	18	-	701
Interest income	1	1	22	(22)	2
Total interest charges, net	184	239	324	(22)	725
Income tax expense (benefit)[a]	268	311	(99)	-	480
Ongoing Earnings	541	530	(200)	-	871
Total assets	16,102	14,484	20,926	(16,453)	35,059
Capital and investment expenditures	1,423	710	17	-	2,150
At and for the year ended December 31, 2010					
Revenues					
Unaffiliated	$ 4,922	$ 5,252	$ 16	$ -	$ 10,190
Intersegment	-	2	248	(250)	-
Total revenues	4,922	5,254	264	(250)	10,190
Depreciation, amortization and accretion	479	426	15	-	920
Interest income	3	1	31	(28)	7
Total interest charges, net	186	258	331	(28)	747
Income tax expense (benefit)[a]	342	267	(87)	-	522
Ongoing Earnings	618	462	(191)	-	889
Total assets	14,899	14,056	21,110	(17,011)	33,054
Capital and investment expenditures	1,382	991	33	(24)	2,382
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]	295	209	(88)	-	416
Ongoing Earnings	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

[a] Income tax expense (benefit) excludes the tax impact of 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. Ongoing Earnings as presented here may not be comparable to similarly

titled measures used by other companies. Ongoing Earnings is computed as GAAP net income attributable to controlling interests less discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Management has identified the following Ongoing Earnings adjustments: CVO mark-to-market adjustments because we are unable to predict changes in their fair value; CR3 indemnification charge (and subsequent adjustments, if any) for estimated future years' joint owner replacement power costs (through the expiration of the indemnification provisions of the joint owner agreement) because GAAP requires that the charge be accounted for in the period in which it becomes probable and estimable rather than the periods to which it relates; and the impact from changes in the tax treatment of the Medicare Part D subsidy because GAAP requires that the impact of the tax law change be accounted for in the period of enactment rather than the affected tax year. Additionally, management does not consider impairments, charges (and subsequent adjustments, if any) recognized for the retirement of generating units prior to the end of their estimated useful lives, merger and integration costs, cumulative prior period adjustments, operating results of discontinued operations and the amount to be refunded to customers through the fuel clause included in the terms of the 2012 settlement agreement to be representative of our ongoing operations and excluded these items in computing Ongoing Earnings.

Reconciliations of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended December 31 follow:

(in millions)	2011	2010	2009
Ongoing Earnings	**$ 871**	$ 889	$ 846
CVO mark-to-market, net of tax benefit of $14 and $- (Note 16)	**(45)**	-	19
Impairment, net of tax benefit of $1, $4 and $1	**(2)**	(6)	(2)
Merger and integration costs, net of tax benefit of $17 (Note 2)	**(46)**	-	-
CR3 indemnification charge, net of tax benefit of $13 (Note 22C)	**(20)**	-	-
Plant retirement charge, net of tax benefit of $1, $1 and $11	**(1)**	(1)	(17)
Amount to be refunded to customers, net of tax benefit of $111 (Note 8C)	**(177)**	-	-
Change in tax treatment of the Medicare Part D subsidy (Note 17)	-	(22)	-
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $7	-	-	(10)
Continuing income attributable to noncontrolling interests, net of tax	**7**	7	4
Income from continuing operations	**587**	867	840
Discontinued operations, net of tax	**(5)**	(4)	(79)
Net income attributable to noncontrolling interests, net of tax	**(7)**	(7)	(4)
Net income attributable to controlling interests	**$ 575**	$ 856	$ 757

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 U.S. Environmental Protection Agency (EPA) and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residuals, 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. In June 2010, the EPA proposed two options for new rules to regulate coal combustion residuals. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residuals management and disposal under federal hazardous waste rules. The other option would have the EPA set design and performance

standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste with enforcement by the courts or state laws. The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. A final rule is expected in late 2012. 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. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

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 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.

We measure our liability for environmental 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 in O&M expense on the Income Statements 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 tables contain information about accruals for probable and estimable costs related to various environmental sites, which are included in other current liabilities and other liabilities and deferred credits on the Balance Sheets:

PROGRESS ENERGY

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2008	**$ 31**	**$ 22**	**$ 53**
Amount accrued for environmental loss contingencies	3	13	16
Expenditures for environmental loss contingencies	(12)	(15)	(27)
Balance, December 31, 2009[a]	**22**	**20**	**42**
Amount accrued for environmental loss contingencies	8	13	21
Expenditures for environmental loss contingencies	(10)	(18)	(28)
Balance, December 31, 2010[a]	**20**	**15**	**35**
Amount accrued for environmental loss contingencies	**2**	**8**	**10**
Expenditures for environmental loss contingencies	**(5)**	**(17)**	**(22)**
Balance, December 31, 2011[a]	**$ 17**	**$ 6**	**$ 23**

[a] Expected to be paid out over one to 15 years.

PEC

(in millions)	MGP and Other Sites
Balance, December 31, 2008	**$ 16**
Amount accrued for environmental loss contingencies	3
Expenditures for environmental loss contingencies	(6)
Balance, December 31, 2009[a]	**13**
Amount accrued for environmental loss contingencies	3
Expenditures for environmental loss contingencies	(4)
Balance, December 31, 2010[a]	**12**
Amount accrued for environmental loss contingencies	**1**
Expenditures for environmental loss contingencies	**(2)**
Balance, December 31, 2011[a]	**$ 11**

[a] Expected to be paid out over one to five years.

PEF

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2008	**$ 15**	**$ 22**	**$ 37**
Amount accrued for environmental loss contingencies	-	13	13
Expenditures for environmental loss contingencies	(6)	(15)	(21)
Balance, December 31, 2009[a]	**9**	**20**	**29**
Amount accrued for environmental loss contingencies	5	13	18
Expenditures for environmental loss contingencies	(6)	(18)	(24)
Balance, December 31, 2010[a]	**8**	**15**	**23**
Amount accrued for environmental loss contingencies	**1**	**8**	**9**
Expenditures for environmental loss contingencies	**(3)**	**(17)**	**(20)**
Balance, December 31, 2011[a]	**$ 6**	**$ 6**	**$ 12**

[a] 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

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. 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 Transformer site located in Raleigh, N.C. (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, 2011 and December 31, 2010, PEC's recorded liability for the site was approximately $5 million. In 2008 and 2009, PEC filed civil actions against 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. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. On March 24, 2010, the federal district court in which this matter is pending denied motions to dismiss filed by a number of defendants, but granted several other motions filed by state agencies and successor entities. The court established a "test case" program providing for a determination of liability on the part of a set of representative defendants. Summary judgment motions and responsive pleadings are being filed by and against these defendants and discovery and briefing will be completed by May 2012. Meanwhile, proceedings with respect to the other defendants have been stayed. The outcome of these matters cannot be predicted.

In 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 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 September 29, 2011, the EPA issued unilateral administrative orders to certain parties, which did not include PEC, directing the performance of remedial activities

with regard to Ward OU1. 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

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.

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 additional distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC.

B. AIR AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations impacting air and water quality, which likely would result in increased capital expenditures and O&M expense. Control equipment installed for compliance with then-existing or proposed laws and regulations may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. PEC has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the North Carolina Clean Smokestacks Act (Clean Smokestacks Act). The air quality controls installed to comply with nitrogen oxides (NOx) and sulfur dioxide (SO_2) requirements under certain sections of the Clean Air Act and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for NOx and SO_2 for our North Carolina units at PEC. PEF has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the CAIR.

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it would develop maximum achievable control technology (MACT) standards. The U.S. District Court for the District of Columbia issued an order requiring the EPA to issue a final MACT standard for power plants. On February 16, 2012, the EPA published the final MACT standards for coal-fired and oil-fired electric steam generating units (EGU MACT). The rule will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. The EGU MACT contains stringent emission limits for mercury, non-mercury metals and acid gases from coal-fired units and hazardous air pollutant metals, acid gases and hydrogen fluoride from oil-fired units. 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. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. We are continuing to evaluate the impacts of the EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC. The outcome of these matters cannot be predicted.

The CAIR, issued by the EPA, 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. A 2008 decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) remanded the CAIR without vacating it for the EPA to conduct further proceedings.

On July 7, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR, slated to take effect on January 1, 2012, contains new emissions trading programs for NOx and SO_2 emissions as

well as more stringent overall emissions targets in 27 states, including North Carolina, South Carolina and Florida. A number of parties including groups which PEC and PEF are members of, filed petitions for reconsideration and stay of, as well as legal challenges to, the CSAPR. On December 30, 2011, the D.C. Court of Appeals issued an order staying the implementation of the CSAPR, pending a decision by the court resolving the challenges to the rule. Oral argument for the CSAPR litigation has been scheduled for April 13, 2012. As a result of the stay of CSAPR, the CAIR will remain in effect. The EPA issued the CSAPR as four separate programs, including the NOx annual trading program, the NOx ozone season trading program, the SO_2 Group 1 trading program and the SO_2 Group 2 trading program. If the CSAPR is upheld, North Carolina and South Carolina are included in the NOx and SO_2 annual trading programs, as well as the NOx ozone season program. North Carolina remains classified as a Group 1 state, which will require additional NOx and SO_2 emission reductions beginning in January 2014. South Carolina remains classified as a Group 2 state with no additional reductions required. Under the CSAPR, Florida is subject only to the NOx ozone season program. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures. We cannot predict the outcome of this matter.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5), which have both been completed and placed in service. Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and No. 2 (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 originally anticipated to be around 2020. As discussed in Note 8B, major construction activities for Levy are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of these developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. Emission allowances are included on the Balance Sheets in inventory and in other assets and deferred debits. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. As previously discussed, the CSAPR establishes new NOx annual and seasonal ozone programs and a new SO_2 trading program. NOx and SO_2 emission allowances applicable to the current CAIR cannot be used to satisfy the new CSAPR programs. SO_2 emission allowances will be utilized by the Utilities to comply with existing Clean Air Act requirements. NOx allowances cannot be utilized to comply with other requirements. As a result of the previously discussed D.C. Court of Appeals order staying the implementation of the CSAPR, the CAIR emission allowance program remains in effect. At December 31, 2011 and December 31, 2010, PEC had an immaterial amount of NOx emission allowances. At December 31, 2011 and December 31, 2010, PEF had approximately $22 million and $28 million, respectively, in NOx emission allowances.

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, 2011, the following tables reflect contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[a]	$ 2,324	$ 2,053	$ 1,644	$ 1,460	$ 1,182	$ 6,437	$ 15,100
Purchased power	459	440	381	391	373	3,104	5,148
Construction obligations[a]	331	216	35	23	4	10	619
Other purchase obligations	153	100	69	61	71	603	1,057
Total	$ 3,267	$ 2,809	$ 2,129	$ 1,935	$ 1,630	$ 10,154	$ 21,924

PEC

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel	$ 1,173	$ 970	$ 760	$ 718	$ 626	$ 1,864	$ 6,111
Purchased power	79	70	64	70	68	376	727
Construction obligations	277	114	25	19	-	-	435
Other purchase obligations	77	44	47	30	38	242	478
Total	$ 1,606	$ 1,198	$ 896	$ 837	$ 732	$ 2,482	$ 7,751

PEF

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[a]	$ 1,151	$ 1,083	$ 884	$ 742	$ 556	$ 4,573	$ 8,989
Purchased power	380	370	317	321	305	2,728	4,421
Construction obligations[a]	54	102	10	4	4	10	184
Other purchase obligations	64	48	22	31	33	361	559
Total	$ 1,649	$ 1,603	$ 1,233	$ 1,098	$ 898	$ 7,672	$ 14,153

[a] PEF signed an EPC agreement on December 31, 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. Due to uncertainty regarding the ultimate magnitude and timing of obligations under the EPC agreement and the Levy nuclear fabrication contract, the table includes only the obligations related to the selected components of long lead time equipment as discussed under "Fuel and Purchased Power" and "Construction Obligations."

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 purchases under these commitments were $2.697 billion, $2.890 billion and $2.921 billion for 2011, 2010 and 2009, respectively. PEC's purchases were $1.398 billion, $1.489 billion and $1.527 billion in 2011, 2010 and 2009, respectively. PEF's purchases were $1.299 billion, $1.401 billion and $1.394 billion in 2011, 2010 and 2009, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are eligible for recovery through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract that contained exit provisions with termination fees for the planned Levy nuclear units. Due to revisions in the construction schedule and startup dates the nuclear fuel fabrication contract was terminated during 2011. (See discussion following under "Construction Obligations.")

Both PEC and PEF have ongoing purchased power contracts, including renewable energy contracts, with other utilities, certain co-generators and qualified facilities (QFs), with expiration dates ranging from 2012 to 2032. These purchased power contracts generally provide for capacity and energy payments or bundled capacity and energy payments. In addition, both PEC and PEF have various contracts to secure transmission rights. Our purchases under purchased power contracts, including transmission costs, were $925 million, $907 million and $756 million for 2011, 2010 and 2009, respectively. PEC's purchases, including transmission costs, were $253 million, $239 million and $171 million in 2011, 2010 and 2009, respectively. PEF's purchases, including transmission costs, were $672 million, $668 million and $585 million in 2011, 2010 and 2009, respectively.

PEC has executed certain firm contracts for approximately 985 MW of purchased power with other utilities, including tolling contracts, with expiration dates ranging from 2019 to 2022 and representing between 33 percent and 100 percent of plant net output. Minimum purchases under these contracts included in the previous table, representing capital-related capacity costs, are approximately $51 million, $52 million, $53 million, $60 million and $60 million for 2012 through 2016, respectively, and $271 million payable thereafter.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 81 MW of firm capacity expiring at various times through 2032. 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 and, therefore, are not included in the previous table.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs. Certain agreements are for the period from July 2012 through May 2033. The estimated total cost to PEC associated with these agreements is approximately $1.510 billion, approximately $380 million of which 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 mid-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 or in PEC's capital lease assets or obligations.

PEF has executed certain firm contracts for approximately 499 MW of purchased power with other utilities with expiration dates ranging from 2012 to 2016 and representing between 12 percent and 25 percent of plant net output. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $53 million, $46 million, $65 million, $65 million and $27 million for 2012 through 2016, respectively.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2012 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. Minimum expected future capacity payments under these contracts are $313 million, $309 million, $238 million, $244 million and $273 million for 2012 through 2016, respectively, and $2.728 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.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $507 million, $703 million and $818 million for 2011, 2010 and 2009, respectively.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $460 million, $555 million and $199 million for 2011, 2010 and 2009, respectively. Payments for 2011 primarily relate to construction of generating facilities at our sites in Wayne County, N.C., and New Hanover County, N.C., as discussed in Note 8B.

PEF has purchase obligations related to capital projects including Levy and various new generation, transmission and environmental compliance projects. Total payments under PEF's construction-related contracts were $47 million, $147 million and $619 million for 2011, 2010 and 2009, respectively, including $6 million, $63 million and $243 million for 2011, 2010 and 2009, respectively, toward long lead equipment and engineering related to the Levy EPC.

The future construction obligations presented in the previous tables for Progress Energy and PEF exclude PEF's Levy EPC agreement. The EPC agreement includes provisions for termination. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. As discussed in Note 8C, in 2010 PEF identified a schedule shift in the Levy project, and major construction activities on Levy have been postponed until after the NRC issues the COL for the plants, which is expected in 2013 if the current licensing schedule remains on track. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges. Prior to the EPC amendment, estimated payments and associated escalations were $8.608 billion for the multi-year contract and did not assume any joint ownership. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict when those obligations will be satisfied or the magnitude of any change. PEF has continued with selected components of long lead time equipment. Work was suspended on the remaining long lead time equipment items, which have total remaining estimated payments and associated escalations of approximately $1.250 billion included in the previously discussed $8.608 billion. We cannot predict the outcome of this matter.

OTHER PURCHASE OBLIGATIONS

We have various other contractual obligations primarily related to PESC service contracts for operational services, PEC service agreements related to its Smith Energy Complex, Wayne County, N.C., and New Hanover County, N.C., generating facilities, and PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $151 million, $124 million and $56 million for 2011, 2010 and 2009, respectively.

PEC has various other purchase obligations, including obligations for long-term service agreements, parts and equipment, limestone supply and fleet vehicles. Total purchases under these contracts were $73 million, $55 million and $14 million for 2011, 2010 and 2009, respectively.

PEF has various other purchase obligations, including long-term service agreements for the Hines Energy Complex and the Bartow Plant. Total payments under these contracts were $54 million, $35 million and $22 million for 2011, 2010 and 2009, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. LEASES

We and the Utilities lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Additionally, the Utilities have entered into certain purchased power agreements, which are classified as leases. 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 other than for purchased power totaled $42 million, $39 million and $37 million for 2011, 2010 and 2009, respectively. Our purchased power expense under agreements classified as operating leases was approximately $62 million, $61 million and $11 million in 2011, 2010 and 2009, respectively.

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 on the Consolidated Statements of Income. See Note 2 regarding our exit plan to vacate and sublease this building.

PEC's rent expense under operating leases other than for purchased power totaled $26 million, $25 million and $26 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million in 2011, 2010 and 2009.

PEC has entered into purchased power agreements that are classified as operating leases. These agreements, which have total minimum payments of approximately $512 million and expire through 2032, primarily relate to two tolling agreements for purchased power of approximately 576 MW (100 percent of net output). Purchased power expense under agreements classified as operating leases was approximately $62 million, $38 million and $11 million in 2011, 2010 and 2009, respectively.

PEF's rent expense under operating leases other than for purchased power totaled $15 million, $14 million and $11 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEF of $4 million in 2011 and $3 million in 2010 and 2009.

PEF has entered into a purchased power tolling agreement that is classified as an operating lease. This agreement for approximately 640 MW (100 percent of net output) has minimum annual payments beginning in June 2012 and expires in 2027 with total minimum payments of approximately $421 million. Purchased power expense under agreements classified as operating leases was approximately $23 million in 2010. PEF had no purchased power expense under operating lease agreements in 2011 and 2009.

PEF has a capital lease for a building and one tolling agreement for purchased power, which is classified as a capital lease of the related plant. PEF entered into the agreement for the building in 2005 and the lease term expires in 2047. The agreement for the building provides for minimum annual payments from 2007 through 2026 and no payments from 2027 through 2047. The minimum annual payments are approximately $5 million, for a total of approximately $103 million. During the last 20 years of the building lease, approximately $51 million of rental expense will be recorded on the Statements of Income. The 517-MW (100 percent of net output) tolling agreement for purchased power has minimum annual payments of approximately $21 million from 2007 through 2024, for a total of approximately $348 million.

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

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Buildings	**$ 267**	$ 267	**$ 30**	$ 30	**$ 237**	$ 237
Less: Accumulated amortization	**(56)**	(46)	**(18)**	(17)	**(38)**	(29)
Total	**$ 211**	$ 221	**$ 12**	$ 13	**$ 199**	$ 208

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 $25 million, $25 million and $26 million for 2011, 2010 and 2009, respectively, which was primarily comprised of PEF's capital lease expense of $23 million, $23 million and $24 million for 2011, 2010 and 2009, respectively.

At December 31, 2011, 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
2012	$ 28	$ 61	$ 2	$ 28	$ 26	$ 27
2013	36	85	10	43	26	36
2014	26	82	-	42	26	35
2015	26	79	-	43	26	34
2016	25	79	-	43	25	34
Thereafter	201	791	6	472	195	318
Minimum annual payments	342	1,177	18	671	324	484
Less amount representing imputed interest	(131)		(6)		(125)	
Total	$ 211	$ 1,177	$ 12	$ 671	$ 199	$ 484

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's rents received are primarily contingent upon usage and totaled $35 million, $33 million, and $34 million for 2011, 2010 and 2009, respectively. PEC's minimum rentals receivable under noncancelable leases are $12 million for 2012 and none thereafter. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $86 million, $85 million and $84 million for 2011, 2010 and 2009, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2012 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, 2011, 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 on the accompanying Balance Sheets.

At December 31, 2011, 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, 2011, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $337 million, including $61 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 related to discontinued operations have no limitations as to time or maximum potential future payments. As part of settlement agreements entered into in 2002, PEF is responsible for providing the joint owners of CR3 a specified amount of generating capacity through the expiration of the indemnification provisions of the joint owner agreement in 2013. Due to the CR3 outage (See Note 8C), PEF has been unable to meet the required generating capacity and has provided replacement power from other generation sources or purchased power. During the year ended December 31, 2011, we and PEF recorded indemnification charges totaling $48 million for estimated joint owner replacement power costs for 2011 and future years, and provided replacement power totaling $21 million. At December 31, 2011 and 2010, we had recorded liabilities related to guarantees and indemnifications to third parties of $63 million and $31 million, respectively. These amounts included $37 million and $6 million for PEF at December 31, 2011 and 2010, respectively. As current estimates change, 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 in guarantees for certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. OTHER COMMITMENTS AND CONTINGENCIES

MERGER

During January and February 2011, Progress Energy and its directors were named as defendants in 11 purported class action lawsuits with 10 lawsuits brought in the Superior Court, Wake County, N.C., and one lawsuit filed in the United States District Court for the Eastern District of North Carolina, each in connection with the Merger (we refer to these lawsuits as the "actions"). The complaints in the actions alleged, among other things, that the Merger Agreement was the product of breaches of fiduciary duty by the individual defendants, in that it allegedly did not provide for full and fair value for Progress Energy's shareholders; that the Merger Agreement contained coercive deal protection measures; and that the Merger Agreement and the Merger were approved as a result, allegedly, of improper self-dealing by certain defendants who would receive certain alleged employment compensation benefits and continued employment pursuant to the Merger Agreement. The complaints in the actions also alleged that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. As relief, the plaintiffs in the actions sought, among other things, to enjoin completion of the Merger.

Additionally, the complaint in the federal action was amended in early April 2011 to include allegations that the defendants violated federal securities laws in connection with statements contained in the registration statement filed on Form S-4 by Duke Energy related to the Merger (the Registration Statement).

On March 31, 2011, counsel for the federal action plaintiff sent a derivative demand letter to Mr. William D. Johnson, Chairman, President and CEO of Progress Energy, demanding that the Progress Energy board of directors desist from moving forward with the Merger, make certain disclosures and engage in an auction of the company. Also on March 31, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 13, 2011, counsel for the federal action plaintiff sent another derivative demand letter to Mr. Johnson further demanding that the Progress Energy board of directors desist from moving forward with the Merger unless certain changes are made to the Merger Agreement and additional disclosures are made. Also on April 13, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 25, 2011, the Progress Energy board of directors established a special committee of disinterested directors to conduct a review and evaluation of the allegations and legal claims set forth in the derivative demand letters. The special committee investigated the allegations and legal claims and determined there was no basis to pursue the claims.

By order dated June 17, 2011, the court consolidated the state court cases. On June 21, 2011, the plaintiffs in the state court actions filed a verified consolidated amended complaint in the consolidated state court actions alleging breach of fiduciary duty by the individual defendants, and that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. The verified consolidated amended complaint further alleged that the Registration Statement and amendments filed on April 8, April 25, and May 13, 2011, failed to disclose material facts, giving rise to plaintiffs' claims.

On July 11, 2011, solely to avoid the costs, risks and uncertainties inherent in litigation and to allow its shareholders to vote on the proposals required in connection with the Merger at its special meeting of its shareholders, Progress Energy entered into a memorandum of understanding with plaintiffs in the consolidated state court actions and other named defendants to settle the consolidated action and all related claims that were or could have been asserted in other actions, subject to court approval. The details of the settlement were set forth in a notice sent to Progress Energy's shareholders of record that were members of the class as of July 5, 2011.

On November 29, 2011, the court entered a final order and judgment approving the settlement as fair, reasonable and adequate and awarded legal fees and expenses to plaintiffs' counsel of $550,000. The court dismissed the action with prejudice and released and fully discharged all claims, including federal claims, which had been or could be in the future asserted in the action or in any court, tribunal or proceeding. On December 8, 2011, the federal action was voluntarily dismissed.

ENVIRONMENTAL

We are subject to federal, state and local regulations regarding environmental matters (See Note 21).

Hurricane Katrina

In May 2011, PEC and PEF were named in a class action lawsuit filed in the U.S. District Court for the Southern District of Mississippi. Plaintiffs claim that PEC and PEF, along with numerous other utility, oil, coal and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina. Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. We believe the plaintiffs' claim is without merit; however, we cannot predict the outcome of this matter.

Water Discharge Permit

On October 5, 2011, Earthjustice, on behalf of the Sierra Club and Florida Wildlife Federation, filed a petition seeking review of the water discharge permit issued to CR1, CR2 and CR3 raising a number of technical and legal

issues with respect to the permit. A settlement has been tentatively reached providing for the withdrawal of the petition and issuance of a revised water discharge permit identical in form to the one under appeal but with an 18 month term. The current permit has a five year term. The settlement, if finalized, will fully resolve the current dispute. We cannot predict the outcome of this matter.

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 U.S. 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. The Utilities have asserted over $90 million in damages incurred between January 31, 1998, and December 31, 2005, the time period set by the court for damages in this case.

On June 14, 2011, the judge in the U.S. Court of Federal Claims issued a ruling to award the Utilities substantially all their asserted damages. In September 2011, after the government dismissed its notice of appeal, the judgment became final. As a result, in September 2011, PEC recorded the $92 million award as an offset for past spent fuel storage costs incurred, of which $27 million was O&M expense. PEC received the cash award in January 2012.

On December 12, 2011, the Utilities filed another complaint in the U.S. Court of Federal Claims against the DOE, claiming damages incurred from January 1, 2006, through December 31, 2010. The damages stem from the same breach of contract asserted in the previous litigation. The Utilities may file subsequent damage claims as they incur additional costs. We 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 (renamed 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 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 and (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.

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. On December 18, 2009, we appealed the Broward County judgment to the Florida Fourth District Court of Appeals. Also 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. The appellate briefing process has been completed. Oral argument was held on September 27, 2011. 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 verdict in the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

CLAIM OF HOLDER OF CONTINGENT VALUE OBLIGATIONS

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us in the Supreme Court of the State of New York, County of New York. Davidson Kempner is a holder of CVOs (See Note 16) and alleged that we improperly deducted escrow deposits in 2005 in determining net after-tax cash flow under the agreement governing the CVOs and that by taking this position, we breached our obligation under the agreement to exercise good faith and fair dealing. The plaintiffs alleged that this breach caused injury to the holders of CVOs in the approximate amount of $42 million. The plaintiffs requested declaratory judgment to require that we deduct the escrowed payments in 2006.

On August 2, 2011, the parties filed a Stipulation of Discontinuance without Prejudice to dismiss the state lawsuit so that certain of the plaintiffs could file a federal lawsuit against us. On August 9, 2011, M.H. Davidson & Co. and Davidson Kempner International, Ltd. filed a lawsuit against us in the United States District Court for the Southern District of New York with the same allegations and seeking the same relief as the prior state lawsuit. On October 3, 2011, we entered a settlement agreement and release with Davidson Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. The parties to the federal lawsuit filed a Stipulation of Discontinuance with Prejudice dismissing the lawsuit on October 12, 2011.

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. In addition, Florida Progress guaranteed the payment of all distributions related to the 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 two guarantees considered together constitute a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and the 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 related to the Subordinated Notes 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, 2011, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional, and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances, and as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a 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, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 4,379	$ 4,528	$ -	$ 8,907
Affiliate revenues	-	-	272	(272)	-
Total operating revenues	-	4,379	4,800	(272)	8,907
Operating expenses					
Fuel used in electric generation	-	1,506	1,387	-	2,893
Purchased power	-	778	315	-	1,093
Operation and maintenance	10	881	1,407	(262)	2,036
Depreciation, amortization and accretion	-	169	532	-	701
Taxes other than on income	-	350	218	(6)	562
Other	-	(1)	35	-	34
Total operating expenses	10	3,683	3,894	(268)	7,319
Operating (loss) income	(10)	696	906	(4)	1,588
Other income (expense)					
Interest income	-	1	2	(1)	2
Allowance for equity funds used during construction	-	32	71	-	103
Other, net	(61)	5	(4)	2	(58)
Total other (expense) income, net	(61)	38	69	1	47
Interest charges					
Interest charges	279	276	205	-	760
Allowance for borrowed funds used during construction	-	(14)	(21)	-	(35)
Total interest charges, net	279	262	184	-	725
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(350)	472	791	(3)	910
Income tax (benefit) expense	(127)	170	275	5	323
Equity in earnings of consolidated subsidiaries	798	-	-	(798)	-
Income from continuing operations	575	302	516	(806)	587
Discontinued operations, net of tax	-	(3)	(2)	-	(5)
Net income	575	299	514	(806)	582
Net income attributable to noncontrolling interests, net of tax	-	(4)	-	(3)	(7)
Net income attributable to controlling interests	$ 575	$ 295	$ 514	$ (809)	$ 575

Condensed Consolidating Statement of Income
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 5,268	$ 4,922	$ -	$ 10,190
Affiliate revenues	-	-	248	(248)	-
Total operating revenues	-	5,268	5,170	(248)	10,190
Operating expenses					
Fuel used in electric generation	-	1,614	1,686	-	3,300
Purchased power	-	977	302	-	1,279
Operation and maintenance	7	912	1,345	(237)	2,027
Depreciation, amortization and accretion	-	426	494	-	920
Taxes other than on income	-	362	225	(7)	580
Other	-	17	13	-	30
Total operating expenses	7	4,308	4,065	(244)	8,136
Operating (loss) income	(7)	960	1,105	(4)	2,054
Other income (expense)					
Interest income	7	2	5	(7)	7
Allowance for equity funds used during construction	-	28	64	-	92
Other, net	(1)	1	(3)	3	-
Total other income, net	6	31	66	(4)	99
Interest charges					
Interest charges	282	293	211	(7)	779
Allowance for borrowed funds used during construction	-	(13)	(19)	-	(32)
Total interest charges, net	282	280	192	(7)	747
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(283)	711	979	(1)	1,406
Income tax (benefit) expense	(111)	267	378	5	539
Equity in earnings of consolidated subsidiaries	1,027	-	-	(1,027)	-
Income from continuing operations	855	444	601	(1,033)	867
Discontinued operations, net of tax	1	(1)	(4)	-	(4)
Net income	856	443	597	(1,033)	863
Net (income) loss attributable to noncontrolling interests, net of tax	-	(4)	1	(4)	(7)
Net income attributable to controlling interests	$ 856	$ 439	$ 598	$ (1,037)	$ 856

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, 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 from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	-	(79)
Net income	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	-	(3)	2	(3)	(4)
Net income attributable to controlling interests	$ 757	$ 407	$ 478	$ (885)	$ 757

Condensed Consolidating Balance Sheet
December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,523	$ 11,887	$ 87	$ 22,497
Current assets					
Cash and cash equivalents	117	92	21	-	230
Receivables, net	-	372	517	-	889
Notes receivable from affiliated companies	53	-	219	(272)	-
Regulatory assets	-	244	31	-	275
Derivative collateral posted	-	123	24	-	147
Prepayments and other current assets	128	852	1,049	(87)	1,942
Total current assets	298	1,683	1,861	(359)	3,483
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,043	-	-	(14,043)	-
Regulatory assets	-	1,602	1,423	-	3,025
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	559	1,088	-	1,647
Other assets and deferred debits	140	242	856	(486)	752
Total deferred debits and other assets	14,183	2,403	3,367	(10,874)	9,079
Total assets	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,021	$ 4,728	$ 5,646	$ (10,374)	$ 10,021
Noncontrolling interests	-	4	-	-	4
Total equity	10,021	4,732	5,646	(10,374)	10,025
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,543	4,482	3,693	-	11,718
Total capitalization	13,564	9,557	9,398	(10,410)	22,109
Current liabilities					
Current portion of long-term debt	450	-	500	-	950
Short-term debt	250	233	188	-	671
Notes payable to affiliated companies	-	238	34	(272)	-
Derivative liabilities	38	268	130	-	436
Other current liabilities	161	839	1,112	(84)	2,028
Total current liabilities	899	1,578	1,964	(356)	4,085
Deferred credits and other liabilities					
Noncurrent income tax liabilities	-	837	1,976	(458)	2,355
Regulatory liabilities	-	1,071	1,543	86	2,700
Other liabilities and deferred credits	18	1,566	2,234	(8)	3,810
Total deferred credits and other liabilities	18	3,474	5,753	(380)	8,865
Total capitalization and liabilities	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059

Condensed Consolidating Balance Sheet
December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,189	$ 10,961	$ 90	$ 21,240
Current assets					
Cash and cash equivalents	110	270	231	-	611
Receivables, net	-	497	536	-	1,033
Notes receivable from affiliated companies	14	48	115	(177)	-
Regulatory assets	-	105	71	-	176
Derivative collateral posted	-	140	24	-	164
Prepayments and other current assets	30	751	984	(273)	1,492
Total current assets	154	1,811	1,961	(450)	3,476
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,316	-	-	(14,316)	-
Regulatory assets	-	1,387	987	-	2,374
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	554	1,017	-	1,571
Other assets and deferred debits	75	238	894	(469)	738
Total deferred debits and other assets	14,391	2,179	2,898	(11,130)	8,338
Total assets	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,023	$ 4,957	$ 5,686	$ (10,643)	$ 10,023
Noncontrolling interests	-	4	-	-	4
Total equity	10,023	4,961	5,686	(10,643)	10,027
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,989	4,182	3,693	-	11,864
Total capitalization	14,012	9,486	9,438	(10,679)	22,257
Current liabilities					
Current portion of long-term debt	205	300	-	-	505
Notes payable to affiliated companies	-	175	3	(178)	-
Derivative liabilities	18	188	53	-	259
Other current liabilities	278	1,002	1,184	(273)	2,191
Total current liabilities	501	1,665	1,240	(451)	2,955
Deferred credits and other liabilities					
Noncurrent income tax liabilities	3	528	1,608	(443)	1,696
Regulatory liabilities	-	1,084	1,461	90	2,635
Other liabilities and deferred credits	29	1,416	2,073	(7)	3,511
Total deferred credits and other liabilities	32	3,028	5,142	(360)	7,842
Total capitalization and liabilities	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 756	$ 706	$ 1,251	$ (1,098)	$ 1,615
Investing activities					
Gross property additions	-	(818)	(1,248)	-	(2,066)
Nuclear fuel additions	-	(15)	(211)	-	(226)
Purchases of available-for-sale securities and other investments	-	(4,438)	(579)	-	(5,017)
Proceeds from available-for-sale securities and other investments	-	4,441	529	-	4,970
Changes in advances to affiliated companies	(38)	48	(104)	94	-
Contributions to consolidated subsidiaries	(11)	-	-	11	-
Other investing activities	(24)	121	29	1	127
Net cash used by investing activities	(73)	(661)	(1,584)	106	(2,212)
Financing activities					
Issuance of common stock, net	53	-	-	-	53
Dividends paid on common stock	(734)	-	-	-	(734)
Dividends paid to parent	-	(513)	(585)	1,098	-
Net decrease in short-term debt	250	233	185	(1)	667
Proceeds from issuance of long-term debt, net	495	296	495	-	1,286
Retirement of long-term debt	(700)	(300)	-	-	(1,000)
Changes in advances from affiliated companies	-	63	31	(94)	-
Contributions from parent	-	10	1	(11)	-
Other financing activities	(40)	(12)	(4)	-	(56)
Net cash (used) provided by financing activities	(676)	(223)	123	992	216
Net increase (decrease) in cash and cash equivalents	7	(178)	(210)	-	(381)
Cash and cash equivalents at beginning of year	110	270	231	-	611
Cash and cash equivalents at end of year	$ 117	$ 92	$ 21	$ -	$ 230

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 16	$ 1,181	$ 1,562	$ (222)	$ 2,537
Investing activities					
Gross property additions	-	(1,014)	(1,231)	24	(2,221)
Nuclear fuel additions	-	(38)	(183)	-	(221)
Purchases of available-for-sale securities and other investments	-	(6,391)	(618)	-	(7,009)
Proceeds from available-for-sale securities and other investments	-	6,395	595	-	6,990
Changes in advances to affiliated companies	15	(2)	188	(201)	-
Return of investment in consolidated subsidiaries	54	-	-	(54)	-
Contributions to consolidated subsidiaries	(171)	-	-	171	-
Other investing activities	113	60	3	(115)	61
Net cash provided (used) by investing activities	11	(990)	(1,246)	(175)	(2,400)
Financing activities					
Issuance of common stock, net	434	-	-	-	434
Dividends paid on common stock	(717)	-	-	-	(717)
Dividends paid to parent	-	(102)	(100)	202	-
Dividends paid to parent in excess of retained earnings	-	-	(54)	54	-
Net decrease in short-term debt	(140)	-	-	-	(140)
Proceeds from issuance of long-term debt, net	-	591	-	-	591
Retirement of long-term debt	(100)	(300)	-	-	(400)
Changes in advances from affiliated companies	-	(201)	-	201	-
Contributions from parent	-	33	152	(185)	-
Other financing activities	-	(14)	(130)	125	(19)
Net cash (used) provided by financing activities	(523)	7	(132)	397	(251)
Net (decrease) increase in cash and cash equivalents	(496)	198	184	-	(114)
Cash and cash equivalents at beginning of year	606	72	47	-	725
Cash and cash equivalents at end of year	$ 110	$ 270	$ 231	$ -	$ 611

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 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 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	-
Return of investment in consolidated subsidiaries	12	-	-	(12)	-
Contributions to consolidated subsidiaries	(688)	-	-	688	-
Other investing activities	-	-	(1)	-	(1)
Net cash used by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock, net	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	(629)	-	-	-	(629)
Net increase (decrease) in short-term debt	100	(371)	(110)	-	(381)
Proceeds from issuance of long-term debt, net	1,683	-	595	-	2,278
Retirement of long-term debt	-	-	(400)	-	(400)
Changes in advances from affiliated companies	-	170	-	(170)	-
Contributions from parent	-	653	49	(702)	-
Other financing activities	(2)	(12)	12	10	8
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

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 2,167**	**$ 2,256**	**$ 2,747**	**$ 1,737**
Operating income	**451**	**428**	**690**	**19**
Income (loss) from continuing operations	**187**	**180**	**293**	**(73)**
Net income (loss)	**185**	**178**	**293**	**(74)**
Net income (loss) attributable to controlling interests	**184**	**176**	**291**	**(76)**
Common stock data				
Basic and diluted earnings per common share				
Income (loss) from continuing operations attributable to controlling interests, net of tax	**0.63**	**0.60**	**0.98**	**(0.25)**
Net income (loss) attributable to controlling interests	**0.62**	**0.60**	**0.98**	**(0.25)**
Dividends declared per common share	**0.620**	**0.620**	**0.620**	**0.259**
Market price per share				
High	**46.83**	**49.03**	**52.42**	**56.33**
Low	**42.55**	**45.20**	**42.05**	**49.37**
2010				
Operating revenues	$ 2,535	$ 2,372	$ 2,962	$ 2,321
Operating income	494	440	753	367
Income from continuing operations	191	181	365	130
Net income	190	180	365	128
Net income attributable to controlling interests	190	180	361	125
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.67	0.62	1.23	0.43
Net income attributable to controlling interests	0.67	0.62	1.23	0.42
Dividends declared per common share	0.620	0.620	0.620	0.620
Market price per share				
High	41.35	40.69	44.82	45.61
Low	37.04	37.13	38.96	43.08

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.

In the third quarter of 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement. As a result, we recognized $50 million of expense, net of tax, related to the change in the CVOs' fair market value. See Note 16 for additional information.

During the fourth quarter of 2011, we recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,133**	**$ 1,060**	**$ 1,332**	**$ 1,003**
Operating income	**228**	**192**	**329**	**136**
Net income	**131**	**107**	**199**	**79**
Net income attributable to controlling interests	**131**	**107**	**199**	**79**
2010				
Operating revenues	$ 1,263	$ 1,117	$ 1,414	$ 1,128
Operating income	266	196	402	207
Net income	136	111	236	119
Net income attributable to controlling interests	138	112	234	119

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.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,032**	**$ 1,193**	**$ 1,414**	**$ 730**
Operating income (loss)	**216**	**234**	**361**	**(113)**
Net income (loss)	**102**	**113**	**203**	**(104)**
2010				
Operating revenues	$ 1,270	$ 1,252	$ 1,543	$ 1,189
Operating income	222	244	344	149
Net income	102	119	180	52

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.

During the fourth quarter of 2011, PEF recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

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 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 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, 2011. 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, 2011, 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, 2011, 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, 2011, 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. and Subsidiaries (the "Company") as of December 31, 2011, based on 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, 2011, 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, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

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, 2011. 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, 2011, PEC maintained effective internal control over financial reporting.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting for PEC. As PEC is a non-accelerated filer, management's report is not subject to attestation by our independent registered public accounting firm pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002.

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, 2011, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

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, 2011. 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, 2011, PEF maintained effective internal control over financial reporting.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting for PEF. As PEF is a non-accelerated filer, management's report is not subject to attestation by our independent registered public accounting firm pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002.

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, 2011, 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 and PEC's directors will be set forth in Progress Energy's and PEC's definitive proxy statements for the 2012 Annual Meetings of Shareholders or will be filed with the SEC as part of an amendment to the Annual Report on Form 10-K/A within 120 days after the end of our fiscal year and is incorporated by reference herein.

b) Information regarding both Progress Energy's and PEC's executive officers is set forth in PART I and is 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 website at www.progress-energy.com/investor and is available in print at no cost 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 website 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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 2012 Annual Meeting of Shareholders or will be filed as part of amendments to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

g) The following are available on our website 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

h) Our 2012 Annual Meeting of Shareholders will be held on August 8, 2012, unless the Merger with Duke Energy has been completed by that date, in which case no 2012 Annual Meeting of Shareholders will be held. Shareholder proposals submitted for inclusion in the proxy statement for our 2012 Annual Meeting must be received no later than May 1, 2012, at our principal executive offices, addressed to the attention of:

John R. McArthur
Executive Vice President, General Counsel and Corporate Secretary
Progress Energy, Inc.
P.O. Box 1551
Raleigh, North Carolina 27602-1551

Upon receipt of any such proposal, we will determine whether or not to include such proposal in the proxy statement and proxy in accordance with regulations governing the solicitation of proxies.

A Progress Energy shareholder who otherwise intends to present business at the 2012 Annual Meeting of Shareholders, or who wishes to nominate a candidate for director, must comply with our By-Laws. Our By-Laws require, among other things, that for nominations of persons for election to the board of directors or the proposal of business not included in the notice of meeting to be considered by the shareholders at an annual meeting, a shareholder must give timely written notice thereof. To be timely for the 2012 Annual Meeting of Shareholders, our Corporate Secretary must receive that notice not later than May 1, 2012, and the Corporate Secretary must receive notice of a shareholder's intention to present other business not later than May 1, 2012. The notice must contain and be accompanied by certain information as specified in our By-Laws. We reserve the right to reject, rule out of order or take other appropriate action with respect to any proposal that does not comply with these or other applicable requirements.

Any shareholder desiring a copy of our By-Laws will be furnished one without charge upon written request to the Corporate Secretary. A copy of the By-Laws, as amended and restated on May 10, 2006, was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, and is available at the SEC's website at *www.sec.gov*.

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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 and PEC knows to be the beneficial owner of more than 5 percent of any class of its voting securities is set forth in its definitive proxy statement for the 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is incorporated by reference herein.

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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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 2012 Annual Meeting of Shareholders or will be filed as part of an amendment to the Annual Report on Form 10-K/A, and is 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. Progress Energy's Controller (the 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 and tax 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 5 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 2012 Annual Meeting of Shareholders or will be filed with the SEC as part of an amendment to the Annual Report on Form 10-K/A, and is 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.

	2011	2010
Audit fees	**$ 1,884,000**	$ 1,736,000
Audit-related fees	**8,000**	50,000
Tax fees	**4,000**	4,000
Total	**$ 1,896,000**	$ 1,790,000

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, (iii) accounting consultations for prospective transactions not arising directly from the audits, and (iv) accounting research tool subscriptions.

Tax fees include fees billed for tax compliance matters.

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 was 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, 2011, 2010 and 2009:

Schedule II – Valuation and Qualifying Accounts – Progress Energy, Inc.	247
Schedule II – Valuation and Qualifying Accounts – Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	248
Schedule II – Valuation and Qualifying Accounts – Florida Power Corporation d/b/a Progress Energy Florida, Inc.	249

   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 December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 35**	**$ 10**	**$ 1**	**$ (19)[b]**	**$ 27**
Inventory valuation[c]	**17**	**2**	**-**	**(2)**	**17**
Fossil fuel plants dismantlement reserve	**144**	**4**	**-**	**-**	**148**
Nuclear refueling outage reserve	**15**	**5**	**-**	**-**	**20**
Deferred tax asset valuation allowance	**60**	**11**	**-**	**-**	**71**
2010					
Uncollectible accounts	$ 18	$ 18	$ 24 [b]	$ (25)	$ 35
Inventory valuation[c]	14	3	-	-	17
Fossil fuel plants dismantlement reserve	143	4	-	(3)	144
Nuclear refueling outage reserve	5	13	-	(3)	15
Deferred tax asset valuation allowance	55	5	-	-	60
2009					
Uncollectible accounts	$ 18	$ 32	$ -	$ (32)	$ 18
Inventory valuation[c]	-	14	-	-	14
Fossil fuel plants dismantlement reserve	145	1	-	(3)	143
Nuclear refueling outage reserve	14	18	-	(27)	5
Deferred tax asset valuation allowance	55	-	-	-	55

[a] Deductions from valuation accounts represent write-offs, net of recoveries, or the release of valuation allowances.
[b] Includes $6 million deduction in 2011 and $18 million charge in 2010 related to other noncustomer receivables.
[c] 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 December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 10**	**$ 2**	**$ -**	**$ (3)**	**$ 9**
Inventory valuation[b]	**17**	**2**	**-**	**(2)**	**17**
2010					
Uncollectible accounts	$ 8	$ 3	$ 2	$ (3)	$ 10
Inventory valuation[b]	14	3	-	-	17
2009					
Uncollectible accounts	$ 6	$ 14	$ 1	$ (13)	$ 8
Inventory valuation[b]	-	14	-	-	14

(a) Deductions from valuation accounts represent write-offs, net of recoveries.

(b) Relates to the impact of PEC's 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 December 31
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
Valuation and qualifying accounts deducted on the balance sheet from the related assets:					
2011					
Uncollectible accounts	**$ 25**	**$ 8**	**$ 1**	**$ (16)[b]**	**$ 18**
Fossil fuel plants dismantlement reserve	**144**	**4**	**-**	**-**	**148**
Nuclear refueling outage reserve	**15**	**5**	**-**	**-**	**20**
2010					
Uncollectible accounts	$ 10	$ 15	$ 22 [b]	$ (22)	$ 25
Fossil fuel plants dismantlement reserve	143	4	-	(3)	144
Nuclear refueling outage reserve	5	13	-	(3)	15
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

[a] Deductions from valuation accounts represent write-offs, net of recoveries.
[b] Includes $6 million deduction in 2011 and $18 million charge in 2010 related to other noncustomer receivables.

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 28, 2012

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 28, 2012
/s/ John D. Baker II (John D. Baker II)	Director	February 28, 2012
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	February 28, 2012
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	February 28, 2012
/s/ James B. Hyler, Jr. (James B. Hyler, Jr.)	Director	February 28, 2012
/s/ Robert W. Jones (Robert W. Jones)	Director	February 28, 2012
/s/ W. Steven Jones (W. Steven Jones)	Director	February 28, 2012
/s/ Melquiades R. Martinez (Melquiades R. Martinez)	Director	February 28, 2012
/s/ E. Marie McKee (E. Marie McKee)	Director	February 28, 2012

/s/ John H. Mullin, III (John H. Mullin, III)	Director	February 28, 2012
/s/ Charles W. Pryor, Jr. (Charles W. Pryor, Jr.)	Director	February 28, 2012
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	February 28, 2012
/s/ Theresa M. Stone (Theresa M. Stone)	Director	February 28, 2012
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	February 28, 2012

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 28, 2012

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	February 28, 2012
/s/ Jeffrey A. Corbett (Jeffrey A. Corbett)	Director	February 28, 2012
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 28, 2012
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2012
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 28, 2012
/s/ James Scarola (James Scarola)	Director	February 28, 2012
/s/ Paula J. Sims (Paula J. Sims)	Director	February 28, 2012
/s/ Lloyd M. Yates (Lloyd M. Yates)	Director	February 28, 2012

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 28, 2012

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 28, 2012
/s/ Vincent M. Dolan (Vincent M. Dolan)	Director	February 28, 2012
/s/ Michael A. Lewis (Michael A. Lewis)	Director	February 28, 2012
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 28, 2012
/s/ John R. McArthur (John R. McArthur)	Director	February 28, 2012
/s/ Mark F. Mulhern (Mark F. Mulhern)	Director	February 28, 2012
/s/ Paula J. Sims (Paula J. Sims)	Director	February 28, 2012

EXHIBIT INDEX

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
*2a(1)	Agreement and Plan of Merger, dated as of January 8, 2011, by and among Duke Energy Corporation, Diamond Acquisition Corporation and Progress Energy, Inc. (filed as Exhibit 2.1 to the Current Report on Form 8-K, dated January 8, 2011, File No. 1-15929).	X		
*3a(1)	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(2)	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(3)	Articles of Amendment to the Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), dated 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(4)	Articles of Amendment to the Amended and Restated Articles of Incorporation of Progress Energy, Inc., dated 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(5)	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 September 20, 2010 (filed as Exhibit 3.1 to the Florida Power Corporation Current Report on Form 8-K, dated			X

	September 20, 2010, File No. 1-3274).	
*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	X

	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); the Seventy-sixth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated January 8, 2009, File No. 1-3382); the Seventy-seventh Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated June 18, 2009, File No. 1-3382); and the Seventy-eighth Supplemental Indenture (Exhibit 4 to PEC Current Report on Form 8-K dated September 12, 2011, 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	X

	(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); the Forty-eighth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on June 18, 2008); the Forty-ninth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on March 25, 2010); and the Fiftieth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on August 18, 2011).			
*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		X	

	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).		
*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. Amended and Restated Credit Agreement dated as of February 15, 2012 (filed as Exhibit 10.1 to Current Report on Form 8-K dated February 15, 2012, File No. 1-15929).	X	

*10b(2)	Carolina Power & Light Company 3-Year $750,000,000 Credit Agreement, dated as of October 15, 2010 (filed as Exhibit 10.1 to Current Report on Form 8-K dated October 15, 2010, File No. 1-15929, 1-3382 and 1-3274).		X	
*10b(3)	Florida Power Corporation 3-Year $750,000,000 Credit Agreement, dated as of October 15, 2010 (filed as Exhibit 10.2 to Current Report on Form 8-K dated October 15, 2010, File No. 1-15929, 1-3382 and 1-3274).			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-	X	X	X

	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).			
+*10c(10)	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(11)	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(12)	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(13)	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(14)	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(15)	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).	X		
+*10c(16)	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(17)	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		
+*10c(18)	Employment Agreement Term Sheet for William D. Johnson in connection with the Agreement and Plan of Merger, dated as of January 8, 2011, by and among Duke Energy Corporation, Diamond Acquisition Corporation and Progress Energy, Inc. (Exhibit C to the Agreement and Plan of Merger filed as Exhibit 2.1 to the Current Report on Form 8-K, dated January 8, 2011, File No. 1-15929).	X		
+*10c(19)	Form of Letter Agreement, dated January 8, 2011, executed by certain officers of Progress Energy, Inc., waiving certain rights under Progress Energy, Inc.'s Management Change-in-Control Plan and their employment agreements (filed as Exhibit 10.1 to the Current Report on Form 8-K dated January 8, 2011, File No. 1-15929).	X		
+*10c(20)	Deferred Compensation Plan for Key Management Employees of Progress Energy, Inc., amended and restated effective July 13, 2011 (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(21)	Executive and Key Manager 2009 Performance Share Sub-Plan, Exhibit A to 2007 Equity Incentive Plan, amended and restated effective July 12, 2011 (filed as Exhibit 10(b) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274.	X	X	X
+*10c(22)	Amended Management Incentive Compensation Plan of Progress Energy, Inc., amended and restated effective July 12, 2011 (filed as Exhibit 10(c) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(23)	Progress Energy, Inc. Management Change-in-Control Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(d) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(24)	Progress Energy, Inc. Amended and Restated Management Deferred Compensation Plan, revised and restated effective July 12, 2011 (filed as Exhibit 10(e) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X

+*10c(25)	Progress Energy, Inc. Non-Employee Director Deferred Compensation Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(f) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(26)	Progress Energy, Inc. Non-Employee Director Stock Unit Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(g) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(27)	Amended and Restated Progress Energy, Inc. Restoration Retirement Plan, amended and restated effective July 13, 2011 (filed as Exhibit 10(h) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(28)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., amended and restated effective July 13, 2011 (filed as Exhibit 10(i) to Quarterly Report on Form 10-Q for the period ended September 30, 2011, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+10c(29)	Form of Progress Energy, Inc. Restricted Stock Unit Award Agreement (Graded Vesting), effective September 15, 2011.	X	X	X
+10c(30)	Form of Progress Energy, Inc. Restricted Stock Unit Award Agreement (Cliff Vesting), effective September 15, 2011.	X	X	X
+10c(31)	First Amendment to the Progress Energy, Inc. Amended and Restated Management Deferred Compensation Plan, effective December 14, 2011.	X	X	X
+10c(32)	First Amendment to the Progress Energy, Inc. Amended Management Incentive Compensation Plan, effective December 14, 2011.	X	X	X
*10d(1)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company, Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between Southern Natural Gas Company 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	X		X

	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.)			
*10d(2)	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 and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.	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	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	X	X
101.SCH	XBRL Taxonomy Extension Schema Document	X	X	X
101.CAL	XBRL Taxonomy Calculation Linkbase Document	X	X	X
101.LAB	XBRL Taxonomy Label Linkbase Document	X	X	X
101.PRE	XBRL Taxonomy Presentation Linkbase Document	X	X	X
101.DEF	XBRL Taxonomy Definition Linkbase Document	X	X	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 15 (b) 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, PEC and PEF from the Annual Report on Form 10-K for the year ended December 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements 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, which are tagged as blocks of text in respect to PEC and PEF's disclosures.

In accordance with Rule 406T of Regulation S-T, the XBRL-related information for PEC and PEF 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 and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2011**	2010 [a]	2009 [a]	2008 [a]	2007 [a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income from continuing operations	**$ 910**	$ 1,406	$ 1,237	$ 1,173	$ 1,036
Fixed charges, as below	**827**	846	813	768	677
Deduct:					
Capitalized interest[b]	**35**	32	39	40	17
Pre-tax income (loss) attributable to noncontrolling interests of subsidiaries that have not incurred fixed charges	**3**	3	-	5	9
Preference security dividend requirements of consolidated subsidiaries	**6**	7	7	7	7
Total earnings, as defined	**$ 1,693**	$ 2,210	$ 2,004	$ 1,889	$ 1,680
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	**$ 769**	$ 788	$ 774	$ 679	$ 618
Estimate of interest within rental expense	**52**	51	32	82	52
Preference security dividend requirements of consolidated subsidiaries	**6**	7	7	7	7
Total fixed charges, as defined	**$ 827**	$ 846	$ 813	$ 768	$ 677
Ratio of Earnings to Fixed Charges	**2.05**	2.61	2.46	2.46	2.48
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined[c]	**2.05**	2.61	2.46	2.46	2.48

[a] Prior periods have been revised primarily to include (1) interest within discontinued operations and (2) purchased power agreements classified as leases in the estimate of interest within rental expense.

[b] Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Consolidated Statements of Income.

[c] For all periods presented, we had no preferred stock outstanding.

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)	2011	2010 [a]	2009 [a]	2008 [a]	2007 [a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income	$ 772	$ 952	$ 791	$ 832	$ 796
Fixed charges, as below	235	227	219	231	226
Deduct:					
Capitalized interest[b]	21	19	12	12	5
Pre-tax loss attributable to noncontrolling interests of subsidiaries that have not incurred fixed charges	-	(1)	(2)	-	-
Total earnings, as defined	$ 986	$ 1,161	$ 1,000	$ 1,051	$ 1,017
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	$ 205	$ 205	$ 207	$ 219	$ 215
Estimate of interest within rental expense	30	22	12	12	11
Total fixed charges, as defined	235	227	219	231	226
Preferred dividends, as defined	4	5	5	5	5
Total fixed charges and preferred dividends combined	$ 239	$ 232	$ 224	$ 236	$ 231
Ratio of Earnings to Fixed Charges	4.20	5.11	4.57	4.55	4.50
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	4.13	5.00	4.46	4.45	4.40

[a] Prior periods have been revised primarily to include purchased power agreements classified as leases in the estimate of interest within rental expense.

[b] Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Consolidated Statements of Income.

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)	2011	2010 [a]	2009 [a]	2008 [a]	2007 [a]
EARNINGS, AS DEFINED:					
Add:					
Pre-tax income	$ 494	$ 729	$ 671	$ 566	$ 461
Fixed charges, as below	275	300	278	305	224
Deduct:					
Capitalized interest[b]	14	13	27	28	12
Total earnings, as defined	$ 755	$ 1,016	$ 922	$ 843	$ 673
FIXED CHARGES, AS DEFINED:					
Interest on debt, including capitalized portion	$ 253	$ 271	$ 258	$ 236	$ 185
Estimate of interest within rental expense	22	29	20	69	39
Total fixed charges, as defined	275	300	278	305	224
Preferred dividends, as defined	2	2	2	2	2
Total fixed charges and preferred dividends combined	$ 277	$ 302	$ 280	$ 307	$ 226
Ratio of Earnings to Fixed Charges	2.75	3.39	3.32	2.76	3.00
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	2.73	3.36	3.29	2.75	2.98

(a) Prior periods have been revised primarily to include purchased power agreements classified as leases in the estimate of interest within rental expense.

(b) Excludes equity costs related to allowance for equity funds used during construction that are included in other income (expense) on the Statements of Income.

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, 2011. 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

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. 333-155541 on Form S-8, Registration Statement No. 333-155543 on Form S-8 and Registration Statement No. 333-178020 on Form S-3 of our reports dated February 28, 2012, relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc. and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2012

EXHIBIT (3)-b

Prospectus Supplement
(To Prospectus dated November 18, 2008)

Progress Energy

$300,000,000

Florida Power Corporation d/b/a

Progress Energy Florida, Inc.

First Mortgage Bonds

3.10% Series due 2021

The bonds will mature on August 15, 2021. We will pay interest on the bonds on February 15 and August 15 of each year, beginning February 15, 2012. The bonds will be issued only in denominations of $2,000 and integral multiples of $1,000 above that amount. We may redeem some or all of the bonds at any time at the redemption prices described in this prospectus supplement. See "Description of Bonds — Redemption — Optional Redemption." There is no sinking fund for the bonds. The bonds are not obligations of, nor guaranteed by, Progress Energy, Inc., our corporate parent.

The bonds are secured by the lien of our mortgage and rank equally with all of our other first mortgage bonds from time to time outstanding. The lien of our mortgage is discussed under "Description of First Mortgage Bonds — Ranking and Security" on page 6 of the accompanying prospectus.

We do not intend to list the bonds on any securities exchange or to include them in any automated quotation system.

Investing in our bonds involves risks. See "Risk Factors" on page S-6 of this prospectus supplement and the Risk Factors sections of our most recent Annual Report on Form 10-K and our most recent Quarterly Report on Form 10-Q.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of the bonds or determined that this prospectus supplement or the accompanying prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

	Per Bond	Total
Public Offering Price	99.796%	$299,388,000
Underwriting Discount	0.650%	$ 1,950,000
Proceeds to Us Before Expenses	99.146%	$297,438,000

The public offering price set forth above does not include accrued interest, if any. Interest on the bonds will accrue from their issue date and must be paid by the purchasers if the bonds are delivered after that date.

The bonds are expected to be delivered in global form through the book-entry delivery system of The Depository Trust Company, including for the accounts of Euroclear Bank S.A./N.V., as operator of the Euroclear System, and Clearstream Banking société anonyme, against payment in New York, New York on or about August 18, 2011.

Joint Book-Running Managers

Barclays Capital **Citigroup** **Goldman, Sachs & Co.**

Co-Managers

Mitsubishi UFJ Securities

SunTrust Robinson Humphrey

KeyBanc Capital Markets

The Williams Capital Group, L.P.

The date of this prospectus supplement is August 15, 2011

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Prospectus Supplement

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ABOUT THIS PROSPECTUS SUPPLEMENT

This document is in two parts. The first part is this prospectus supplement, which describes the specific terms of the bonds we are offering and certain other matters relating to us and our financial condition. The second part, the base prospectus, provides more general information about the securities that we may offer from time to time, some of which may not apply to the bonds we are offering hereby. Generally, when we refer to the prospectus, we are referring to both parts of this document combined. If the description of the bonds varies between this prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

You should rely only on the information contained in this document or to which this document refers you or that is contained in any free writing prospectus relating to the bonds. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not making an offer of the bonds in any jurisdiction where an offer or sale of them is not permitted. The information in this prospectus supplement may only be accurate as of the date of this document. Our business, financial condition, results of operations and prospects may have changed since that date.

Unless we have indicated otherwise, or the context otherwise requires, references in this prospectus supplement to "Florida Power," "Progress Energy Florida," "we," "us," and "our," or similar terms, are to Florida Power Corporation d/b/a Progress Energy Florida, Inc. References in this prospectus supplement to "bonds" are to the 3.10% First Mortgage Bonds due August 15, 2021. The bonds are not obligations of, nor guaranteed by, Progress Energy, Inc., our corporate parent.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

We have included in this document, and in the documents incorporated by reference into this document, "forward-looking statements," as defined by the Private Securities Litigation Reform Act of 1995. We have used the words or phrases such as "anticipate," "will likely result," "will continue," "intend," "may," "expect," "believe," "plan," "will," "estimate," "should" and variations of such words and similar expressions in this document and in the documents incorporated by reference to identify such forward-looking statements. Forward-looking statements, by their nature, involve estimates, projections, goals, objectives, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond our control. Many, but not all, of the factors that may impact actual results are discussed under the heading "Safe Harbor For Forward-Looking Statements" in the accompanying prospectus and under the heading "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2010, and our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2011, which are incorporated by reference into this document, and under the "Risk Factors" section contained in this prospectus supplement. You should carefully read these sections. New factors emerge from time to time, and it is not possible for our management to predict all of such factors or to assess the effect of each such factor on our business.

Any forward-looking statement speaks only as of the date on which it is made, and, except to fulfill our obligations under the United States securities laws, we undertake no obligation to update any such statement to reflect events or circumstances after the date on which it is made.

PROSPECTUS SUPPLEMENT SUMMARY

The following summary is qualified in its entirety by the more detailed information appearing elsewhere in this prospectus supplement, the accompanying prospectus, the financial statements and other documents incorporated by reference and any related free writing prospectus. You should carefully read the "Risk Factors" sections that are contained in this prospectus supplement, the accompanying prospectus, our Annual Report on Form 10-K for the year ended December 31, 2010, and our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2011, which are incorporated by reference into this document, to determine whether an investment in our bonds is appropriate for you.

Progress Energy Florida

We are a regulated public utility engaged in the generation, transmission, distribution and sale of electricity within an approximately 20,000 square mile service area. Our service area includes the cities of St. Petersburg and Clearwater, as well as the central Florida area surrounding Orlando.

At June 30, 2011, we were providing electric services, retail and wholesale, to approximately 1.6 million customers. For the six months ended June 30, 2011, approximately 60% of our base revenues were derived from residential customers, 22% from commercial customers, 7% from wholesale customers, 6% from governmental customers and 5% from industrial customers.

At June 30, 2011, we had installed summer generating capacity of 10,025 megawatts, including approximately 120 megawatts of jointly-owned generating capacity, through a system of 14 power plants. For the six months ended June 30, 2011, our energy supply was comprised of approximately 55% gas and oil, 27% coal and 18% purchased power.

Summary of the Offering

The following is a brief summary of the terms of this offering. For a more complete description of the terms of the bonds, see "Description of Bonds" beginning on page S-8 of this prospectus supplement and "Description of First Mortgage Bonds" beginning on page 4 of the accompanying prospectus.

Issuer	Florida Power Corporation d/b/a Progress Energy Florida, Inc. The bonds are not obligations of, nor guaranteed by, our parent company, Progress Energy, Inc.
Bonds Offered	We are offering $300,000,000 aggregate principal amount of first mortgage bonds.
Interest Rate	3.10% per year.
Maturity Date	August 15, 2021.
Interest Payment Dates	Interest on the bonds will be payable semi-annually in arrears on February 15 and August 15, beginning February 15, 2012.
Optional Redemption	We may redeem some or all of the bonds at any time prior to May 15, 2021 (three months prior to their maturity date) at the applicable redemption prices described under "Description of Bonds — Redemption — Optional Redemption," plus accrued and unpaid interest to the date of redemption. The bonds are redeemable on and after May 15, 2021 (three months prior to their maturity date), in whole or in part, at a price of 100% plus accrued interest.
Special Redemption	Upon the occurrence of specific events, we may redeem, at our option, the bonds, together with all other outstanding first mortgage bonds, in whole, but not in part, at the make-whole redemption price described under "Description of Bonds — Redemption — Special Redemption," plus accrued and unpaid interest to the redemption date.
Ranking	The bonds will be secured by the lien of the Mortgage, as defined in the accompanying prospectus, and will rank equally with all other outstanding first mortgage bonds. See "Description of Bonds — Ranking and Security." At June 30, 2011, we had outstanding approximately $4.341 billion in aggregate principal amount of first mortgage bonds (approximately $4.041 billion after giving effect to the July 15, 2011 maturity of the $300 million 6.65% First Mortgage Bonds due 2011).
Sinking Fund	There is no sinking fund for the bonds.
Issuance of Additional First Mortgage Bonds	Under the terms of the Mortgage, as of May 31, 2011, we could issue additional first mortgage bonds in amounts equal to approximately (i) $2.2 billion based upon the bondable value of property additions ($1.9 billion after giving effect to this offering) and (ii) $555.5 million based upon the amount of previously authenticated first mortgage bonds that have been cancelled or delivered for cancellation (approximately $855.5 million after giving effect to the July 15, 2011 maturity of the $300 million 6.65% First Mortgage Bonds due 2011).

Further Issues of the Bonds	Initially, the bonds will be limited to $300 million in aggregate principal amount. We may, subject to the provisions of the Mortgage, "reopen" the bonds and issue additional bonds without the consent of the holders of the bonds.
Use of Proceeds	We intend to use the net proceeds from the sale of the bonds of approximately $295.8 million, after deducting underwriting discounts and estimated offering expenses, to repay a portion of our outstanding short-term debt. For additional information, see "Use of Proceeds."
Trustee	The trustee under the Mortgage is The Bank of New York Mellon. In the normal course of business, the trustee or its affiliates may, from time to time, provide certain commercial banking, investment banking and securities underwriting services to us and our affiliates.

Summary Financial Information

In the table below, we provide you with our summary financial information. The information is only a summary, and you should read it together with the financial information incorporated by reference in this document. See "Documents Incorporated by Reference" on page S-22 of this prospectus supplement and "Where You Can Find More Information" on page ii of the accompanying prospectus.

	Six Months Ended June 30,		Year Ended December 31,		
	2011	2010	2010	2009	2008
	(In Millions of Dollars, except for Ratios)				
Income Statement Data:					
Operating revenues	$ 2,225	$ 2,522	$ 5,254	$ 5,251	$ 4,731
Operating income	450	466	959	802	680
Total interest charges, net	130	127	258	231	208
Net income	215	221	453	462	385
Balance Sheet Data (end of period):					
Total assets	13,907	13,693	14,056	13,100	12,471
Total debt (including capital lease obligations)	4,759	4,701	4,699	4,620	4,848
Other Data:					
Ratio of earnings to fixed charges(a)	3.54x	3.81x	3.66x	3.57x	3.37x
Capital expenditures(b)	$ 432	$ 556	$ 1,052	$ 1,527	$ 1,595

(a) Ratios for the periods ended June 30 represent the ratios for the twelve-month periods ending on those dates. We define "earnings" as income before income taxes plus fixed charges and "fixed charges" as the sum of interest on long-term debt, other interest and an imputed interest factor included in rentals. The ratio of earnings to fixed charges for the years ended December 31, 2007 and 2006 were 3.45x and 4.28x, respectively.

(b) We define "capital expenditures" as gross property and nuclear fuel additions.

RISK FACTORS

Investing in our securities involves risks that could affect us and our business as well as the energy industry generally. Please see the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2010 and our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2011, which are incorporated by reference into this document. Much of the business information as well as the financial and operational data contained in our risk factors is updated in our periodic reports, which are also incorporated by reference into this document. Before purchasing our securities, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2010, our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2011 and the other information in this prospectus supplement and the accompanying prospectus, as well as the documents incorporated by reference herein and any related free writing prospectus. Each of the risks described could result in a decrease in the value of our securities and your investment therein.

USE OF PROCEEDS

We intend to use the net proceeds from the sale of the bonds of approximately $295.8 million, after deducting underwriting discounts and estimated offering expenses, to repay a portion of our outstanding short-term debt. We used $300 million of the proceeds of short-term debt incurred to retire our 6.65% First Mortgage Bonds due 2011 at their maturity on July 15, 2011. At July 31, 2011, we had an outstanding short-term debt balance, representing primarily commercial paper borrowings, of approximately $350 million with a weighted average maturity of approximately 15 days and a weighted average interest rate of approximately 0.38%.

CAPITALIZATION AND SHORT-TERM DEBT

The following table sets forth our capitalization and short-term debt as of June 30, 2011. For a discussion of the application of the proceeds of this offering, see "Use of Proceeds."

	As of June 30, 2011 (In Millions of Dollars)	
Short-term Debt		
Current Portion of Long-term Debt(a)	$ 300	3.2%
Other Short-term Debt(b)	73	0.8%
Long-term Debt		
First Mortgage Bonds	4,032	42.4%
Other Long-term Debt	150	1.6%
Capital Lease Obligations	204	2.1%
Total Debt	4,759	50.1%
Preferred Stock — Redemption Not Required	34	0.4%
Common Stock Equity	4,703	49.50%
Total Capitalization and Debt	$9,496	100.0%

(a) Represents $300 million aggregate principal amount of our 6.65% First Mortgage Bonds due July 15, 2011 that were subsequently retired at maturity.

(b) Represents primarily outstanding commercial paper borrowings. Subsequent to June 30, 2011 we had additional commercial paper borrowings and at July 31, 2011, the balance of our other short-term debt was approximately $350 million. A portion of our other short-term debt will be repaid with the proceeds of this offering.

DESCRIPTION OF BONDS

We will issue the bonds under an Indenture, dated as of January 1, 1944, with The Bank of New York Mellon, as successor trustee (the "Mortgage Trustee"). The Indenture is supplemented by supplemental indentures. In the following discussion, we will refer to the Indenture and all indentures supplemental to the Indenture together as the "Mortgage."

Please read the following information concerning the bonds in conjunction with the statements under "Description of First Mortgage Bonds" in the accompanying prospectus, which the following information supplements and, in the event of any inconsistencies, supersedes. Capitalized terms not defined in this prospectus supplement are used as defined in the Mortgage and supplemental indenture governing the bonds or as otherwise provided in the accompanying prospectus.

General

We will initially offer $300,000,000 aggregate principal amount of our first mortgage bonds. We are issuing the bonds as a new series of first mortgage bonds under our Mortgage. The Fiftieth Supplemental Indenture, to be dated as of August 1, 2011, supplements, and will become a part of, the Mortgage and establishes the specific terms of the bonds. Except as provided under "— Basis for Issuance of the Bonds," we may, at any time, without the consent of the holders of the bonds, issue additional first mortgage bonds having the same ranking, interest rate, maturity and other terms as the bonds being offered hereby. Any such additional bonds, together with the bonds offered hereby, will be taken to constitute the same series of bonds under the Mortgage.

The bonds are not obligations of, or guaranteed by, Progress Energy, Inc., our corporate parent.

Basis for Issuance of the Bonds

We will issue the bonds under the Mortgage based upon the value of bondable property additions.

As of May 31, 2011, we could issue under the Mortgage:

- based upon the value of bondable property additions, up to approximately $2.2 billion (approximately $1.9 billion after giving effect to this offering) of additional first mortgage bonds; and
- based upon the amount of previously authenticated first mortgage bonds that have been canceled or delivered for cancellation, approximately $555.5 million of additional first mortgage bonds (approximately $855.5 million after giving effect to the July 15, 2011 maturity of the $300 million 6.65% First Mortgage Bonds due 2011).

Form and Denomination

The bonds will initially be represented by one or more global securities that will be deposited with, or on behalf of, The Depository Trust Company, or DTC, and registered in the name of a nominee of DTC. Investors may hold interests in the bonds through DTC if they are participants in DTC or indirectly through organizations that are participants in DTC, including Euroclear Bank S.A./N.V., as operator of the Euroclear system, or Clearstream Banking, société anonyme. The bonds will be sold in denominations of $2,000 and integral multiples of $1,000 above that amount. For more information on DTC, see "— The Depositary" below.

Maturity, Interest and Payment

The bonds will mature on August 15, 2021.

We will pay interest on the bonds at 3.10% per year. Interest on the bonds will accrue from and including the date of original issuance. We will pay interest on the bonds on February 15 and August 15 of each year,

beginning February 15, 2012. We will pay interest on the bonds to the person(s) in whose name(s) the bonds are registered at the close of business on the tenth calendar day next preceding the interest payment date, provided, however, that so long as the bonds are registered in the name of DTC, its nominee or a successor depositary, the record date for interest payable on any interest payment date shall be the close of business on the business day immediately preceding such interest payment date for the bonds so registered. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months. If a due date for the payment of interest or principal falls on a day that is not a business day, then the payment will be made on the next succeeding business day, and no interest will accrue on the amounts payable for the period from and after the original due date and until the next business day.

Pursuant to the Mortgage, we will pay interest, to the extent enforceable under law, on any overdue installment of interest on the bonds at the highest rate of interest payable on any of the first mortgage bonds outstanding under the Mortgage.

Ranking and Security

The bonds will be secured by the lien of the Mortgage and will rank equally with all our other first mortgage bonds from time to time outstanding. At June 30, 2011, we had approximately $4.341 billion in aggregate principal amount of first mortgage bonds outstanding (approximately $4.041 billion after giving effect to the July 15, 2011 maturity of the $300 million 6.65% First Mortgage Bonds due 2011). In the opinion of our counsel, the Mortgage constitutes a first mortgage lien, subject only to permitted encumbrances and liens, on substantially all of the fixed properties owned by us, except miscellaneous properties specifically excepted. After-acquired property is covered by the lien of the Mortgage, subject to existing liens at the time such property is acquired.

Dividend Restrictions

As of June 30, 2011, we had retained earnings of approximately $2.958 billion. None of our retained earnings were restricted by provisions of the Mortgage described in the accompanying prospectus that restrict the amount of retained earnings that we can use to pay cash dividends on our common stock.

Redemption

The bonds are redeemable prior to maturity, as set forth below. We have agreed that before any applicable redemption date, we will deposit with the Mortgage Trustee a sum of money equal to the applicable redemption price. If we elect to redeem any bonds, we will notify the Mortgage Trustee of our election at least 45 days prior to the redemption date, or a shorter period acceptable to the Mortgage Trustee, including in the notice of redemption a reasonably detailed computation of the redemption price. Our failure to make the required deposit will constitute a completed default under the Mortgage on the specified redemption date, and the subject bonds or, in the case of a special redemption, all outstanding first mortgage bonds, including the bonds, shall immediately become due and payable.

Optional Redemption

Prior to May 15, 2021 (three months prior to their maturity date), we may redeem some or all of the bonds at any time at a redemption price equal to the greater of:

- 100% of the principal amount of the bonds then outstanding to be redeemed; or
- the sum of the present values of the remaining scheduled payments of principal and interest on the bonds being redeemed, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the treasury rate plus 15 basis points,

plus, in each case, accrued and unpaid interest on the principal amount being redeemed to the redemption date.

At any time on or after May 15, 2021 (three months prior to their maturity date), the bonds will be redeemable, in whole at any time or in part from time to time, at our option, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed plus accrued interest thereon to the date of redemption.

"Comparable treasury issue," means the United States Treasury security or securities selected by an independent investment banker (as defined below) as having an actual or interpolated maturity comparable to the remaining term of the bonds being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such bonds.

"Comparable treasury price," means, with respect to any redemption date, the average of the reference treasury dealer quotations (as defined below) for such redemption date.

"Independent investment banker," means one of the reference treasury dealer(s) (as defined below) appointed by us.

"Reference treasury dealer," means Barclays Capital Inc., Citigroup Global Markets Inc. or Goldman, Sachs & Co. and their respective successors, and one additional primary U.S. Government securities dealer in The City of New York (each a "primary treasury dealer") selected by us. If any reference treasury dealer shall cease to be a primary treasury dealer, we will substitute another primary treasury dealer for that dealer.

"Reference treasury dealer quotations," means, with respect to each reference treasury dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the comparable treasury issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by such reference treasury dealer at 3:30 p.m. New York time on the third business day preceding such redemption date.

"Treasury rate," means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to actual or interpolated maturity (on a day count basis) of the comparable treasury issue, assuming a price for the comparable treasury issue (expressed as a percentage of its principal amount) equal to the comparable treasury price for such redemption date.

So long as the bonds are registered in the name of DTC, its nominee or a successor depositary, if we elect to redeem less than all of the bonds, DTC's practice is to determine by lot the amount of the interest of each Direct Participant, as defined below, in the bonds to be redeemed. At all other times, the Mortgage Trustee shall draw by lot, in such manner as it deems appropriate, the particular bonds, or portions of them, to be redeemed. Notice of redemption shall be given by mail not less than 30 nor more than 90 days prior to the date fixed for redemption to the holders of bonds to be redeemed, which, as long as the bonds are held in the book-entry only system, will be DTC, its nominee or a successor depositary. On and after the date fixed for redemption (unless we default in the payment of the redemption price and interest accrued thereon to such date), interest on the bonds, or the portions of them so called for redemption, shall cease to accrue. For further information on DTC and its practices, see "— The Depositary" below.

Special Redemption

The bonds, together with all other outstanding first mortgage bonds, are redeemable as a whole, but not in part, at our option, at the prices set forth below, upon not more than 90 days' notice in the event that:

- all of our outstanding common stock is acquired by some governmental body or instrumentality and we elect to redeem all outstanding first mortgage bonds, including the bonds; or
- all, or substantially all, of the mortgaged and pledged property constituting bondable property, as defined in the Mortgage, that is then subject to the Mortgage as a first lien shall be released from the lien of the Mortgage pursuant to the provisions thereof, and available moneys held by the Mortgage Trustee, including

any moneys deposited by us for the purpose, are sufficient to redeem all outstanding first mortgage bonds, including the bonds, at the applicable redemption prices (together with accrued interest to the date of redemption) upon the happening of such event.

In the event of a special redemption, the bonds will be redeemable at the make-whole redemption price set forth above under "— Optional Redemption."

Sinking Fund

The bonds will not be entitled to the benefit of any sinking fund, or to a special redemption by operation of a sinking fund.

Concerning the Trustee

The trustee under the Mortgage is The Bank of New York Mellon. In the normal course of business, the Trustee or its affiliates may, from time to time, provide certain commercial banking, investment banking and securities underwriting services to us and our affiliates.

The Depositary

DTC is a:

- limited-purpose trust company organized under the New York Banking Law;
- "banking organization" within the meaning of the New York Banking Law;
- member of the Federal Reserve System;
- "clearing corporation" within the meaning of the New York Uniform Commercial Code; and
- "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934.

DTC holds securities that its Participants, as defined below, deposit with DTC. DTC also facilitates the settlement among Participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in Participants' accounts. This book-entry system eliminates the need for physical movement of securities certificates.

Participants in DTC include direct participants ("Direct Participants") and indirect participants ("Indirect Participants," and, together with Direct Participants, "Participants"). Direct Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is owned by a number of its Direct Participants and by The New York Stock Exchange, Inc., the American Stock Exchange, Inc. and the Financial Industry Regulatory Authority, Inc. Access to the DTC system is also available to Indirect Participants, which include, among others, securities brokers and dealers, banks and trust companies that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly. The rules applicable to DTC and its Participants are on file with the Securities and Exchange Commission ("SEC").

Purchases of bonds under DTC's system must be made by or through Direct Participants, which will receive a credit for the bonds on DTC's records. The ownership interest of each actual purchaser of bonds ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase; rather, Beneficial Owners are expected to receive written confirmations providing details of the transaction as well as periodic statements of their holdings from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction.

To facilitate subsequent transfers, all bonds deposited by Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. The deposit of bonds with DTC and their registration in the name of Cede & Co. effect no change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such bonds are credited, which may or may not be the Beneficial Owners. The Participants will remain responsible for keeping account of their holdings on behalf of their customers.

So long as Cede & Co., as nominee for DTC, is the sole holder of the bonds, the Mortgage Trustee shall treat Cede & Co. as the only holder of the bonds for all purposes, including receipt of all principal of, premium, if any, and interest on such bonds, receipt of notices, and voting and requesting or directing the Mortgage Trustee to take or not to take, or consent to, certain actions.

We, or, at our request, the Mortgage Trustee, will send any redemption notices to DTC. If we redeem less than all of the bonds, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in the bonds to be redeemed.

Neither DTC nor Cede & Co. will consent or vote with respect to the bonds. Under its usual procedures, DTC mails an Omnibus Proxy to us as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the bonds are credited on the record date and includes an attached list identifying such Direct Participants. Further, we believe that it is the policy of DTC that it will take any action permitted to be taken by a holder of bonds only at the direction of one or more Direct Participants to whose account interests in the bonds are credited and only in respect of such portion of the aggregate principal amount of the bonds as to which such Direct Participant or Participants has or have given such direction.

Principal of, and premium, if any, and interest payments on the bonds will be made to DTC. DTC's practice is to credit Direct Participants' accounts on the applicable payment date in accordance with the Direct Participants' respective holdings shown on DTC's records on the calendar day immediately preceding the applicable payment date unless DTC has reason to believe that it will not receive payment. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of the Participants and not of DTC, the Mortgage Trustee or us, subject to applicable statutory or regulatory requirements. Payment of principal, premium, if any, and interest to DTC is our responsibility, or the responsibility of the Mortgage Trustee with funds we provide. Disbursement of such payments to Direct Participants shall be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners shall be the responsibility of Participants.

Neither we, the Mortgage Trustee nor any underwriter makes any representation as to the accuracy of the above description of DTC's business, organization and procedures, which is based on information received from sources we believe to be reliable.

The Mortgage provides that if:

- the depositary gives reasonable notice to us or to the Mortgage Trustee that it is unwilling or unable to continue as depositary and a successor depositary is not appointed by us within 90 days, or
- the depositary ceases to be eligible under the Mortgage and a successor depositary is not appointed by us within 90 days, or
- we decide to discontinue use of the system of book-entry transfers through the depositary or its successor,

the global bonds will be exchanged for bonds in definitive form of like tenor and of an equal aggregate principal amount, in authorized denominations. The depositary will provide to the Mortgage Trustee the name or names in which the Mortgage Trustee is to register these definitive bonds.

We, the underwriters and the Mortgage Trustee have no responsibility or obligation to DTC Participants or the Beneficial Owners with respect to:

- the accuracy of any records maintained by DTC or any Participant;
- the payment by any Participant of any amount due to any Beneficial Owner in respect of the principal of, premium, if any, and interest on, the bonds;
- the delivery or timeliness of delivery by DTC to any Participant or by any Participant to any Beneficial Owner of any notice that is required or permitted under the terms of the Mortgage; or
- any other action taken by DTC or its nominee, Cede & Co., as holder of the bonds.

A further description of DTC's procedures with respect to the bonds is set forth under "Global Securities" in the accompanying prospectus.

Clearstream, Luxembourg. Clearstream, Luxembourg advises that it is incorporated under the laws of Luxembourg as a professional depositary. Clearstream, Luxembourg holds securities for its participating organizations ("Clearstream participants") and facilitates the clearance and settlement of securities transactions between Clearstream participants through electronic book-entry changes in accounts of Clearstream participants, thereby eliminating the need for physical movement of certificates. Clearstream, Luxembourg provides to Clearstream participants, among other things, services for safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Clearstream, Luxembourg interfaces with domestic markets in several countries. As a professional depositary, Clearstream, Luxembourg is subject to regulation by the Luxembourg Commission for the Supervision of the Financial Sector *(Commission de Surveillance du Secteur Financier).* Clearstream participants are recognized financial institutions around the world, including underwriters, securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations and may include the underwriters. Indirect access to Clearstream, Luxembourg is also available to others, such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Clearstream participant, either directly or indirectly.

Distributions with respect to interests in any bonds held beneficially through Clearstream, Luxembourg will be credited to cash accounts of Clearstream participants in accordance with its rules and procedures, to the extent received by the U.S. depositary for Clearstream, Luxembourg.

Euroclear. Euroclear advises that it was created in 1968 to hold securities for participants of Euroclear ("Euroclear participants") and to clear and settle transactions between Euroclear participants through simultaneous electronic book-entry delivery against payment, thereby eliminating the need for physical movement of certificates and any risk from lack of simultaneous transfers of securities and cash. Euroclear includes various other services, including securities lending and borrowing and interfaces with domestic markets in several countries. Euroclear is operated by Euroclear Bank S.A./N.V. (the "Euroclear Operator"). All operations are conducted by the Euroclear Operator, and all Euroclear securities clearance accounts and Euroclear cash accounts are accounts with the Euroclear Operator. Euroclear participants include banks (including central banks), securities brokers and dealers and other professional financial intermediaries and may include the underwriters. Indirect access to Euroclear is also available to other firms that clear through or maintain a custodial relationship with a Euroclear participant, either directly or indirectly.

Securities clearance accounts and cash accounts with the Euroclear Operator are governed by the Terms and Conditions Governing Use of Euroclear and the related Operating Procedures of the Euroclear system, and applicable Belgian law (collectively, the "Terms and Conditions"). The Terms and Conditions govern transfers of securities and cash within the Euroclear system, withdrawals of securities and cash from the Euroclear system, and receipts of payments with respect to securities in the Euroclear system. All securities in the Euroclear system are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts. The Euroclear Operator acts under the Terms and Conditions only on behalf of Euroclear participants, and has no records of or relationship with persons holding through Euroclear participants.

Distributions with respect to any bonds held beneficially through the Euroclear system will be credited to the cash accounts of Euroclear participants in accordance with the Terms and Conditions, to the extent received by the U.S. depositary for the Euroclear system.

Global Clearance and Settlement Procedures. Settlement for any bonds will be made in immediately available funds. Secondary market trading between DTC participants will occur in the ordinary way in accordance with DTC rules. Secondary market trading between Clearstream participants and/or Euroclear participants will occur in the ordinary way in accordance with the applicable rules and operating procedures of Clearstream, Luxembourg and the Euroclear system, as applicable.

Cross-market transfers between persons holding directly or indirectly through DTC on the one hand, and directly or indirectly through Clearstream participants or Euroclear participants, on the other, will be effected through DTC in accordance with DTC rules on behalf of the relevant European international clearing system by its U.S. depositary; however, such cross-market transactions will require delivery of instructions to the relevant European international clearing system by the counterparty in such system in accordance with its rules and procedures and within its established deadlines (European time). The relevant European international clearing system will, if the transaction meets its settlement requirements, deliver instructions to its U.S. depositary to take action to effect final settlement on its behalf by delivering or receiving securities in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Clearstream participants and Euroclear participants may not deliver instructions directly to their respective U.S. depositaries.

Because of time-zone differences, credits of any bonds received in Clearstream, Luxembourg or the Euroclear system as a result of a transaction with a DTC participant will be made during subsequent securities settlement processing and dated the business day following the DTC settlement date. Such credits or any transactions in such bonds settled during such processing will be reported to the relevant Euroclear participant or Clearstream participant on such business day. Cash received in Clearstream, Luxembourg or the Euroclear system as a result of sales of any bonds by or through a Clearstream participant or a Euroclear participant to a DTC participant will be received on the DTC settlement date but will be available in the relevant Clearstream, Luxembourg or the Euroclear system cash account only as of the business day following settlement in DTC.

The information in this section concerning DTC and DTC's book-entry system, Clearstream, Luxembourg and the Euroclear system has been obtained from sources that we believe to be reliable. Neither we nor the underwriters take any responsibility for the accuracy of this information.

MATERIAL U.S. FEDERAL TAX CONSIDERATIONS

The following general discussion summarizes certain material U.S. federal income and, for certain foreign persons, estate tax aspects of the purchase, ownership and disposition of the bonds. This discussion is a summary for general information only and does not consider all aspects of U.S. federal tax that may be relevant to the purchase, ownership and disposition of the bonds. This discussion also does not address the U.S. federal tax consequences of the purchase, ownership or disposition of bonds not held as capital assets within the meaning of Section 1221 of the Internal Revenue Code of 1986, as amended (the "Code"), or the U.S. federal tax consequences to investors subject to special treatment under the U.S. federal tax laws, such as, without limitation:

- dealers in securities or foreign currencies;
- tax-exempt entities;
- banks and other financial institutions;
- thrifts;
- insurance companies;
- persons that hold the bonds as part of a "straddle," "hedge" or "conversion transaction";
- U.S. holders (as defined below) that have a "functional currency" other than the U.S. dollar;
- pass-through entities (e.g., partnerships and grantor trusts) or investors who hold the bonds through pass-through entities;
- certain former citizens or residents of the United States; and
- controlled foreign corporations, passive foreign investment companies and foreign personal holding companies.

In addition, this discussion is limited to the U.S. federal income tax consequences to initial holders that purchase the bonds for cash at their initial "issue price" (i.e., the initial offering price to the public, excluding bond houses and brokers, at which a substantial amount of the bonds is sold) and does not discuss the tax consequences for subsequent purchasers of the bonds. It does not address the effect of the federal alternative minimum tax or describe any tax consequences arising out of the tax laws of any state, local or foreign jurisdiction.

This discussion is based upon the Code, United States Treasury Regulations issued thereunder, Internal Revenue Service ("IRS") rulings and pronouncements and judicial decisions now in effect, all of which are subject to change (possibly with retroactive effect). We have not and will not seek any rulings or opinions from the IRS or counsel regarding the matters discussed below. There can be no assurance that the IRS will not take positions concerning the tax consequences of the purchase, ownership or disposition of the bonds that are different from those discussed below.

This summary is not, and should not be construed to be, legal or tax advice to any particular investor. Persons considering the purchase of bonds should consult their own tax advisors concerning the application of U.S. federal tax laws, as well as the laws of any state, local or foreign taxing jurisdiction, or under any applicable tax treaty, and the possible effect of changes in applicable tax law to their particular situations.

U.S. Holders

The following discussion is limited to the U.S. federal income tax consequences relevant to a "U.S. holder," which for purposes of this discussion means a beneficial owner of a bond that is:

- an individual who is a citizen or resident of the United States;

- a corporation or other entity taxable as a corporation for U.S. federal income tax purposes created or organized under the laws of the United States, any of its states or the District of Columbia;
- an estate, the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if (i) a U.S. court is able to exercise primary supervision over administration of the trust and one or more U.S. persons have authority to control all substantial decisions of the trust, or (ii) in the case of a trust that was treated as a domestic trust under the law in effect prior to 1997, a valid election is in place under applicable Treasury regulations to treat such trust as a domestic trust.

In the case of a holder of the bonds that is classified as a partnership for U.S. federal income tax purposes, the tax treatment of the bonds to a partner of the partnership generally will depend upon the tax status of the partner and the activities of the partnership. A beneficial owner that is a partnership holding the bonds and partners in such a partnership should consult their own tax advisors. Certain U.S. federal tax consequences relevant to a holder other than a U.S. holder are discussed separately below.

Taxation of Stated Interest. Stated interest on the bonds generally will be includable in the income of a U.S. holder as ordinary interest income:

- when it accrues, if you use the accrual method of accounting for U.S. federal income tax purposes; or
- when you receive it, if you use the cash method of accounting for U.S. federal income tax purposes.

Additional Amounts. In the case of an optional redemption of the bonds (see "Description of Bonds — Redemption — Optional Redemption" and "— Special Redemption"), we may be obligated to pay an amount in excess of 100% of the principal amount of the bonds (plus accrued interest thereon). In the case of a default in payment (see "Description of Bonds — Maturity, Interest and Payment"), we may be required to pay additional interest. Under applicable Treasury regulations, the possibility that such amounts will be paid will not affect the amount, timing or character of income recognized by a U.S. holder with respect to the bonds if, as of the date the bonds were issued, there is only a remote chance that such an amount will be paid, the amount is incidental or certain other exceptions apply. We intend to treat these payment contingencies as not affecting the amount, timing or character of income recognized by a U.S. holder with respect to the bonds, and the remainder of this summary assumes such treatment. Our treatment of these payment contingencies is binding on holders except for a holder that discloses its contrary position in the manner required by applicable Treasury regulations. Our treatment of these payment contingencies is not, however, binding on the IRS, and if the IRS were to challenge such treatment, a U.S. holder might be required to accrue income on its bonds in excess of stated interest, and to treat as ordinary income rather than capital gain any gain realized on the taxable disposition of a bond before the resolution of such contingencies. Potential investors are urged to consult their own tax advisors regarding the potential treatment of the bonds as contingent payment debt instruments.

Sale or Other Taxable Disposition of Bonds. Unless a non-recognition provision applies, you must recognize taxable gain or loss on the sale, redemption or other taxable disposition of a bond. The amount of your gain or loss will equal the difference between the amount you receive for the bond (in cash or other property, valued at fair market value), minus the amount attributable to accrued interest on the bond (which will be treated as ordinary interest income to the extent not previously included in gross income), and your adjusted tax basis in the bond. Your adjusted tax basis in a bond generally will equal the amount paid for the bond decreased by any payments received on the bond other than qualified stated interest.

Any such gain or loss will generally constitute capital gain or loss and will be long-term capital gain or loss if you hold the bond for more than one year. Long-term capital gains of certain noncorporate holders are currently eligible for reduced rates of taxation. The deductibility of capital losses is subject to limitations.

Medicare Tax. For taxable years beginning after December 31, 2012, a U.S. holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, will be subject to a

3.8% tax on the lesser of (1) the U.S. holder's "net investment income" (in the case of individuals) or "undistributed net investment income" (in the case of estates and trusts) for the relevant taxable year and (2) the excess of the U.S. holder's "modified adjusted gross income" (in the case of individuals) or "adjusted gross income" (in the case of estates and trusts) for the taxable year over a certain threshold (which in the case of individuals will be between $125,000 and $250,000, depending on the individual's circumstances). A U.S. holder's net investment income generally will include its interest income on the bonds and its net gains from the disposition of the bonds, unless such interest income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). U.S. Holders that are individuals, estates or trusts should consult their own tax advisors regarding the applicability of the Medicare tax to their income and gains in respect of their investment in the bonds.

Information Reporting and Backup Withholding. U.S. holders of bonds may be subject, under certain circumstances, to information reporting and backup withholding on payments of principal and premium, if any, and interest and on the gross proceeds from dispositions of bonds. Backup withholding applies only if the U.S. holder:

- fails to furnish its correct social security or other taxpayer identification number in the manner required by applicable law;
- has been notified by the IRS that it is subject to backup withholding for failure to report properly interest or dividends; or
- fails to certify under penalties of perjury, that it has furnished the correct taxpayer identification number and that the holder has not been notified by the IRS that it is subject to backup withholding.

Backup withholding is not an additional tax. Any amount withheld from a payment to a U.S. holder under the backup withholding rules is allowable as a credit, and may entitle the holder to a refund, against such U.S. holder's U.S. federal income tax liability, provided that the required information is timely furnished to the IRS. Certain persons are exempt from backup withholding, including corporations and financial institutions. U.S. holders should consult their tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such exemption.

We will furnish annually to the IRS, and to record holders of the bonds to whom we are required to furnish such information, information relating to the amount of interest paid and the amount of tax withheld, if any, with respect to payments on the bonds.

Non-U.S. Holders

The following discussion is limited to the U.S. federal income and estate tax consequences relevant to a holder of a bond that is neither a U.S. holder nor a partnership or other pass-through entity for U.S. federal income tax purposes (a "non-U.S. holder").

Non-U.S. holders should consult their tax advisors about any applicable income tax treaties, which may provide for an exemption from or a lower rate of withholding tax, exemption from or reduction of branch profits tax, or other rules different from those described below.

Taxation of Stated Interest. Subject to the discussion of backup withholding below, payments of interest on a bond to any non-U.S. holder will generally not be subject to U.S. federal income or withholding tax, provided that:

- the non-U.S. holder is not:
  - — an actual or constructive owner (either directly or indirectly) of 10% or more of the total voting power of the voting stock of Progress Energy, Inc.;
  - — a controlled foreign corporation related (directly or indirectly) to us through actual or constructive stock ownership; or

— a bank receiving interest described in Section 881(c)(3)(A) of the Code;

- such interest payments are not effectively connected with the conduct by the non-U.S. holder of a trade or business within the United States; and
- we or our paying agent receives:
  - — from the non-U.S. holder, a properly completed Form W-8BEN (or substitute Form W-8BEN or the appropriate successor form) under penalties of perjury, which provides the non-U.S. holder's name and address and certifies that the non-U.S. holder is a non-U.S. person; or
  - — from a security clearing organization, bank or other financial institution that holds the bonds in the ordinary course of its trade or business (a "financial institution") on behalf of the non-U.S. holder, certification under penalties of perjury that such a Form W-8BEN (or substitute Form W-8BEN or the appropriate successor form) has been received by it, or by another such financial institution, from the non-U.S. holder, and a copy of the Form W-8BEN (or substitute Form W-8BEN or the appropriate successor form) is furnished to us.

If a non-U.S. holder cannot satisfy the foregoing requirements, payments of interest made to such non-U.S. holder generally will be subject to U.S. withholding tax currently at the rate of 30%, unless such non-U.S. holder provides us or our agent with a properly executed (i) IRS Form W-8BEN claiming an exemption for or reduction of the withholding tax under the benefit of an applicable tax treaty, or (ii) IRS Form W-8ECI stating that interest paid on a bond is not subject to withholding tax because it is effectively connected with the conduct by the non-U.S. holder of a trade or business in the United States.

If interest on a bond is effectively connected with the conduct by a non-U.S. holder of a trade or business in the United States (and, if certain tax treaties apply, is attributable to a U.S. permanent establishment (or a fixed base in the case of an individual) maintained by the non-U.S. holder), such interest will generally be subject to U.S. federal income tax on a net basis at the rates applicable to U.S. persons (and, in the case of a corporate non-U.S. holder, may also be subject to a branch profits tax equal to 30% of its effectively connected earnings and profits for the taxable year, or lower rate provided by a tax treaty). If interest is subject to U.S. federal income tax on a net basis in accordance with the rules described in the preceding sentence, payments of such interest will not be subject to U.S. withholding tax so long as the holder provides us or the paying agent with appropriate certification.

Sale or Other Taxable Disposition of Bonds. Subject to the discussion of backup withholding below, any gain realized by a non-U.S. holder on the sale, redemption or other disposition of a bond generally will not be subject to U.S. federal income tax, unless:

- such gain is effectively connected with the conduct by such non-U.S. holder of a trade or business in the United States (and, if certain tax treaties apply, is attributable to a U.S. permanent establishment (or a fixed base in the case of an individual) maintained by the non-U.S. holder) in which case such gain will be subject to tax generally in the same manner as described above with respect to effectively connected income; or
- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition and certain other conditions are satisfied, in which case such gain (net of certain U.S. source capital losses) will be subject to a 30% U.S. federal income tax.

Information Reporting and Backup Withholding. In general, payments we make to a non-U.S. holder in respect of the bonds will be reported annually to the IRS. Copies of these information returns also may be made available under the provisions of a specific tax treaty or other agreement to the tax authorities of the country in which the non-U.S. holder resides.

Treasury regulations provide that U.S. federal backup withholding (currently at a rate of 28% and scheduled to increase to 31% in 2013) and certain information reporting will not apply to payments of interest with respect to which either (i) the requisite certification that a non-U.S. holder is not a U.S. person, as described above, has

been received or (ii) an exemption otherwise has been established, provided that neither we nor our paying agent have actual knowledge, or reason to know, that the non-U.S. holder is a U.S. person or that the conditions of any other exemption are not, in fact, satisfied.

The payment of the proceeds from the sale, redemption or other disposition of the bonds to or through the U.S. office of any broker, U.S. or foreign, will be subject to information reporting and possibly backup withholding unless a non-U.S. holder certifies as to its non-U.S. status under penalties of perjury or otherwise establishes an exemption, provided that the broker does not have actual knowledge, or reason to know, that the non-U.S. holder is a U.S. person or that the conditions of any other exemption are not, in fact, satisfied. The payment of the proceeds from the sale, redemption or other disposition of the bonds to or through a non-U.S. office of a non-U.S. broker will not be subject to information reporting or backup withholding unless the non-U.S. broker has certain types of relationships with the United States (a "U.S. related person"). In the case of the payment of the proceeds from the sale, redemption or other disposition of the bonds to or through a non-U.S. office of a broker that is either a U.S. person or a U.S. related person, Treasury regulations require information reporting (but generally not backup withholding) unless the broker has documentary evidence in its files that the owner is a non-U.S. holder and the broker has no knowledge, or reason to know, to the contrary.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules may be refunded or credited against the non-U.S. holder's U.S. federal income tax liability, provided that the requisite information is timely provided to the IRS.

Federal Estate Tax. Unless otherwise provided in an estate tax treaty, a bond held or treated as held by an individual who is a non-U.S. holder at the time of his or her death will not be subject to U.S. federal estate tax, provided that (1) the individual does not actually or constructively own 10% or more of the total voting power of the voting stock of Progress Energy, Inc. and (2) income on the bond was not effectively connected with the conduct by such non-U.S. holder of a trade or business in the United States.

New Legislation. Legislation regarding foreign account tax compliance will impose a withholding tax of 30% on interest and gross proceeds from the disposition of certain debt instruments paid to certain foreign entities unless various information reporting and certain other requirements are satisfied. IRS guidance issued in July 2011 indicates that regulations will be issued that will provide that withholding will only apply to payments of interest made on or after January 1, 2014, and to other "withholdable payments" (including payments of gross proceeds from a sale or other disposition of bonds) made on or after January 1, 2015. Moreover, the withholding tax will not be imposed on payments pursuant to obligations outstanding as of March 18, 2012. In addition, certain account information with respect to U.S. Holders who hold bonds through certain foreign financial institutions may be reportable to the IRS. Investors should consult with their own tax advisors regarding the possible implications of this recently enacted legislation on their investment in the bonds.

THE U.S. FEDERAL INCOME AND ESTATE TAX DISCUSSION SET FORTH ABOVE IS INCLUDED FOR GENERAL INFORMATION ONLY AND MAY NOT BE APPLICABLE DEPENDING UPON A HOLDER'S PARTICULAR CIRCUMSTANCES. HOLDERS SHOULD CONSULT THEIR OWN TAX ADVISORS WITH RESPECT TO THE TAX CONSEQUENCES TO THEM OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF BONDS, INCLUDING THE TAX CONSEQUENCES UNDER STATE, LOCAL, FOREIGN AND OTHER TAX LAWS AND THE POSSIBLE EFFECT OF CHANGES IN APPLICABLE TAX LAWS.

UNDERWRITING

Subject to the terms and conditions set forth in the underwriting agreement dated August 15, 2011 among us and the underwriters named below, we have agreed to sell to each of the underwriters, and each of the underwriters has severally, and not jointly, agreed to purchase, the respective principal amounts of the bonds set forth opposite its name below:

Underwriter	Principal Amount of Bonds
Barclays Capital Inc.	$ 75,000,000
Citigroup Global Markets Inc.	75,000,000
Goldman, Sachs & Co.	75,000,000
Mitsubishi UFJ Securities (USA), Inc.	30,000,000
SunTrust Robinson Humphrey, Inc.	30,000,000
KeyBanc Capital Markets Inc.	9,000,000
The Williams Capital Group, L.P.	6,000,000
Total	$300,000,000

Under the terms and conditions of the underwriting agreement, the underwriters are committed to take and pay for all the bonds, if any are taken; provided, that under certain circumstances relating to a default of one or more underwriters, less than all of the bonds may be purchased. The underwriters propose to offer the bonds in part directly to purchasers at the applicable initial public offering price set forth on the cover page of this prospectus supplement and may offer the bonds to certain securities dealers at this price less a concession not to exceed 0.400% of the principal amount of the bonds. The underwriters may allow, and any such dealers may reallow, a concession to certain other dealers not to exceed 0.250% of the principal amount of the bonds. After the bonds are released for sale to the public, the offering price and other selling terms may from time to time be varied by the underwriters.

The bonds constitute a new issue of securities with no established trading market. We do not intend to apply for listing of the bonds on any national securities exchange or for quotation through any national quotation system. We have been advised by the underwriters that they intend to make a market in the bonds but are not obligated to do so and may discontinue market-making at any time without notice. Therefore, we can give no assurances that a liquid trading market will develop for the bonds, that you will be able to sell your bonds at a particular time, or that the prices that you receive when you sell will be favorable.

In connection with the offering of the bonds, the underwriters may engage in overallotment, stabilizing transactions and syndicate covering transactions in accordance with Regulation M under the Securities Exchange Act of 1934, as amended. Overallotment involves sales in excess of the offering size, which creates a short position for the underwriters. Stabilizing transactions involve bids to purchase the bonds in the open market for the purpose of pegging, fixing or maintaining the price of the bonds. Syndicate covering transactions involve purchases of the bonds in the open market after the distribution has been completed in order to cover short positions. Stabilizing transactions and syndicate covering transactions may cause the price of the bonds to be higher than would otherwise be the case in the absence of those transactions. If the underwriters engage in stabilizing or syndicate covering transactions, they may discontinue them at any time.

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a "Relevant Member State"), each underwriter has represented and agreed that, with effect from and including the date on which the Prospectus Directive is implemented in the Relevant Member State (the "Relevant Implementation Date"), it has not made and will not make an offer of bonds to the public in that Relevant Member State prior to the publication of a prospectus in relation to the bonds which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the

Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of bonds to the public in that Relevant Member State at any time: (a) to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities; (b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year, (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last annual or consolidated accounts; (c) to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the manager for any such offer; or (d) in any other circumstances falling within Article 3(2) of the Prospectus Directive, provided that no such offer of the bonds will require us or the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive (or supplement a prospectus pursuant to Article 16 of the Prospectus Directive). For the purposes of this provision, the expression an "offer of bonds to the public" in relation to any bonds in any Relevant Member State means the communication in any form and by any means of sufficient information of the terms of the offer and the bonds to be offered so as to enable an investor to decide to purchase or subscribe for bonds, as the same may be varied in that Relevant Member State by any measure implementing the Prospectus Directive in that Relevant Member State and the term "Prospectus Directive" means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

Each underwriter has also agreed that: (i) it has complied and will comply with all applicable provisions of the Financial Services and Markets Act 2000 ("FSMA") with respect to anything done by it in relation to the bonds in, from or otherwise involving the United Kingdom; and (ii) it has only communicated, or caused to be communicated, and will only communicate, or cause to be communicated, any invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of any bonds in circumstances in which Section 21(1) of the FSMA does not apply to us.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have engaged, and may in the future engage, in various financial advisory, investment banking and commercial banking services for us and our affiliates in the ordinary course of business for which they have received, and may in the future receive, customary fees. Some of the underwriters or their affiliates are lenders under our revolving credit facility that backs up our or our affiliates' commercial paper programs.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or contribute to payments that the underwriters may be required to make in respect thereof.

We estimate that the total expenses of the offering, including applicable recording and related taxes, but excluding the underwriting discount, will be approximately $1.6 million.

EXPERTS

The financial statements and the related financial statement schedule, incorporated in this prospectus supplement by reference from our Annual Report on Form 10-K for the year ended December 31, 2010, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, which is incorporated herein by reference. Such financial statements and financial statement schedule have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

LEGAL MATTERS

R. Alexander Glenn, our General Counsel, and Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan, L.L.P., our outside counsel, will issue opinions about the legality of the offered securities for us. The underwriters will be advised about issues relating to this offering by their legal counsel, Dewey & LeBoeuf LLP of New York, New York. As of July 31, 2011, Mr. Glenn beneficially owned, or had options to acquire, a number of shares of Progress Energy, Inc. common stock, which represented less than 0.01% of the total outstanding common stock. Mr. Glenn is acquiring additional shares of Progress Energy, Inc. common stock at regular intervals as a participant in the Progress Energy 401(k) Savings & Stock Ownership Plan.

DOCUMENTS INCORPORATED BY REFERENCE

The SEC allows us to "incorporate by reference" the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is an important part of this document, and information that we file later with the SEC will automatically update and supersede the information in this prospectus. Our SEC filing number is 1-3274. We incorporate by reference the documents listed below and any future filings made by us with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended, until we sell all of the securities being registered; provided, however, that we are not incorporating by reference any information furnished under Item 2.02 or Item 7.01 of any Current Report on Form 8-K, unless and, to the extent, specified in any such Current Report.

- Our Annual Report on Form 10-K for the year ended December 31, 2010.
- Our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2011.
- Our Current Reports on Form 8-K filed March 15, April 4, June 27, June 28, and August 15, 2011.

We frequently make our SEC filings on a joint basis with Progress Energy, Inc., our corporate parent, and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), one of our affiliates. Any information included in such SEC filings that relates solely to Progress Energy, Inc. or PEC is not and shall not be deemed to be incorporated by reference into this prospectus supplement or the accompanying prospectus.

You may request a copy of these filings, at no cost, by writing or calling us at the following:

Progress Energy Florida, Inc.
c/o Progress Energy, Inc.
Investor Relations
410 South Wilmington Street
Raleigh, North Carolina 27601
Telephone: (919) 546-7474

Progress Energy

PROSPECTUS

Florida Power Corporation d/b/a
Progress Energy Florida, Inc.

First Mortgage Bonds
Debt Securities
Preferred Stock

These securities are not obligations of, nor guaranteed by, Progress Energy, Inc., our corporate parent.

We will provide specific terms of these securities, and the manner in which they are being offered, in supplements to this prospectus. The securities may be offered on a delayed or continuous basis directly by us, through agents, underwriters or dealers as designated from time to time, through a combination of these methods or any other method as provided in the applicable prospectus supplement. You should read this prospectus and any supplement carefully before you invest. We cannot sell any of these securities unless this prospectus is accompanied by a prospectus supplement.

Investing in our securities involves risks. Before buying our securities, you should refer to the risk factors included in our periodic reports, in prospectus supplements relating to specific offerings and in other information that we file with the Securities and Exchange Commission. See "Risk Factors" on page 1.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus is dated November 18, 2008.

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission (the "SEC") utilizing a "shelf" registration, or continuous offering, process. Under this shelf registration process, we may sell, from time to time, any combination of the securities described in this prospectus in one or more offerings. We may offer any of the following securities: First Mortgage Bonds, other Debt Securities and/or Preferred Stock.

This prospectus provides you with a general description of the securities we may offer. Each time we sell securities, we will provide a prospectus supplement that will contain specific information about the terms of that offering. Any prospectus supplement may also add, update or change information contained in this prospectus. If there is any inconsistency between the information in this prospectus and the prospectus supplement, you should rely on the information in the prospectus supplement. The registration statement we filed with the SEC includes exhibits that provide more detail on descriptions of the matters discussed in this prospectus. You should read this prospectus and the related exhibits filed with the SEC and any prospectus supplement together with additional information described under the heading "WHERE YOU CAN FIND MORE INFORMATION."

OUR COMPANY

We are a regulated public utility incorporated under the laws of Florida in 1899. We are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida, including the cities of St. Petersburg and Clearwater as well as the central Florida area surrounding Orlando. We are an indirect, wholly-owned subsidiary of Progress Energy, Inc., a North Carolina corporation. All of our common stock is held directly by Florida Progress Corporation, a Florida corporation. Since 2003, we have operated our business under the assumed name Progress Energy Florida, Inc., although our legal name is still Florida Power Corporation.

Our principal executive offices are located at 299 First Avenue North, St. Petersburg, Florida 33701. Our telephone number is (727) 820-5151.

Unless the context requires otherwise, references in this prospectus to the terms "we," "us," "our" or other similar terms mean Florida Power Corporation d/b/a Progress Energy Florida, Inc.

USE OF PROCEEDS

Unless we state otherwise in any prospectus supplement, we will use the net proceeds from the sale of any offered securities:

- to finance the construction of new facilities and maintenance of existing facilities;
- to acquire other entities or their assets;
- to refund, repurchase, retire, redeem or reduce outstanding short- or long-term indebtedness; and
- for other general corporate purposes.

In the event that any proceeds are not immediately applied, we may temporarily invest them in federal, state or municipal government or agency obligations, commercial paper, bank certificates of deposit, or repurchase agreements collateralized by federal government or agency obligations, or we may deposit the proceeds with banks.

RATIO OF EARNINGS TO FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

Our ratio of earnings to fixed charges for each of the following periods was:

For the Twelve Months Ended September 30,	
2008	2007
3.43x	3.94x

For the Twelve Months Ended December 31,				
2007	2006	2005	2004	2003
3.45x	4.28x	3.76x	5.17x	5.31x

Our ratio of earnings to combined fixed charges and preferred stock dividends for each of the following periods was:

For the Twelve Months Ended September 30,	
2008	2007
3.40x	3.88x

For the Twelve Months Ended December 31,				
2007	2006	2005	2004	2003
3.42x	4.22x	3.71x	5.08x	5.21x

We define "earnings" as income before income taxes and cumulative effect of change in accounting principles plus fixed charges. We define "fixed charges" as the sum of interest on long-term debt, other interest and an imputed interest factor included in rentals.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports and other information with the SEC. Our SEC filing number is 1-03274. Our SEC filings are available to the public over the Internet at the SEC's web site at http://www.sec.gov. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on its public reference rooms. Additionally, information about us and our SEC filings is available on our web site at http://www.progress-energy.com. **The contents of our web site do not constitute a part of this prospectus or any prospectus supplement hereto.**

DOCUMENTS INCORPORATED BY REFERENCE

The SEC allows us to "incorporate by reference" the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is an important part of this prospectus, and information that we file later with the SEC will automatically update and supersede the information in this prospectus. We incorporate by reference the documents listed below and any future filings made by us with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended, until we sell all of the securities being registered; *provided, however*, that, unless we specifically state otherwise, we are not incorporating by reference any information furnished under Items 2.02 or 7.01 of any Current Report on Form 8-K.

- Our Annual Report on Form 10-K for the year ended December 31, 2007, also referred to as our "2007 Form 10-K." (The financial statements included in the 2007 Form 10-K have been revised in Exhibit 99 to the Form 8-K dated November 6, 2008 to reflect the retrospective implementation of Financial Accounting Standards Board Staff Position FIN 39-1. These revisions had no effect on the reported net income for any of the periods presented.)
- Our Quarterly Reports on Form 10-Q for the quarters ended March 31, June 30 and September 30, 2008.
- Our Current Reports on Form 8-K filed February 28, March 20, June 11, June 18, October 31 and November 6, 2008.

We frequently make our SEC filings on a joint basis with Progress Energy, Inc. ("Progress Energy"), our indirect corporate parent, and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), one of our affiliates. Any information included in such SEC filings that relates solely to Progress Energy or PEC is not and shall not be deemed to be incorporated by reference into this prospectus or any prospectus supplement.

You may request a copy of these filings at no cost, by writing or calling us at the following address:

Progress Energy Florida, Inc.
c/o Progress Energy, Inc.
Investor Relations
410 South Wilmington Street
Raleigh, North Carolina 27601
Telephone: (919) 546-7474

You should rely only on the information incorporated by reference or provided in this prospectus or any prospectus supplement. We have not authorized anyone else to provide you with different information. We are not making any offer of these securities in any jurisdiction where the offer is not permitted. You should not assume that the information in this prospectus or any prospectus supplement is accurate as of any date other than the respective dates on the front of those documents.

RISK FACTORS

Investing in our securities involves risks that could affect us and our business, as well as the energy industry generally. Please see the risk factors described in our 2007 Form 10-K, which is incorporated by reference into this prospectus. Much of the business information, as well as the financial and operational data contained in our risk factors, is updated in our periodic and current reports, which are also incorporated by reference into this prospectus, and future supplements hereto. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial condition or performance. Before purchasing our securities, you should carefully consider the risks discussed in our 2007 Form 10-K and the other information in this prospectus, any supplement hereto, as well as the documents incorporated by reference herein or therein. Each of the risks described could result in a decrease in the value of our securities and your investment therein.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

This prospectus, any supplement hereto, any free writing prospectus and the documents incorporated by reference herein or therein contain or will contain 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 prospectus, any supplement hereto, and any free writing prospectus and in the documents incorporated by reference herein or therein 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 prospectus and speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following:

- the impact of fluid and complex laws and regulations, including those relating to the environment and the Energy Policy Act of 2005 (EPACT);
- the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks;
- the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates;
- our ability to meet current and future renewable energy requirements;
- the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks;
- the impact on our facilities and businesses from a terrorist attack;
- weather and drought conditions that directly influence the production, delivery and demand for electricity;
- recurring seasonal fluctuations in demand for electricity;
- the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process;
- economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets;
- fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process;
- our ability to control costs, including operation and maintenance expense (O&M) and large construction projects;
- the length and severity of the current financial market distress that began in September 2008;
- the ability to successfully access capital markets on favorable terms;
- the stability of commercial credit markets and our access to short-term and long-term credit;
- the impact that increases in leverage may have on us;

- our ability to maintain current credit ratings and the impact on our financial condition and ability to meet cash and other financial obligations in the event our credit ratings are downgraded;
- the investment performance of our nuclear decommissioning trust funds and the assets of our pension and benefit plans;
- the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and
- unanticipated changes in operating expenses and capital expenditures.

These and other risk factors are detailed from time to time in our filings with the SEC. Many, but not all, of the factors that may impact actual results are discussed in the Risk Factors section in our most recent annual report on Form 10-K, which is updated for material changes, if any, in our other SEC filings. You should carefully read these risk factors. 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.

DESCRIPTION OF FIRST MORTGAGE BONDS

General

We will issue First Mortgage Bonds in one or more series under an Indenture, dated as of January 1, 1944, with The Bank of New York Mellon, as successor trustee (the "Mortgage Trustee"), as supplemented by supplemental indentures, including one or more supplemental indentures relating to the First Mortgage Bonds.

In the following discussion, we will refer to the Indenture and all supplements to the Indenture together as the "Mortgage." We will refer to all of our First Mortgage Bonds, including those already issued and those to be issued in the future, as "First Mortgage Bonds." As of September 30, 2008, we had approximately $4.0 billion aggregate principal amount of First Mortgage Bonds outstanding.

The information we are providing you in this prospectus concerning the First Mortgage Bonds and the Mortgage is only a summary of the information provided in those documents and the information is qualified in its entirety by reference to the provisions of the Mortgage. You should consult the First Mortgage Bonds themselves, the Mortgage and other documents for more complete information on the First Mortgage Bonds or any particular series thereof. These documents appear as exhibits to the registration statement of which this prospectus is a part, or are incorporated by reference as exhibits to such registration statement, or will appear as exhibits to other documents that we will file with the SEC, which will be incorporated by reference into this prospectus. The Mortgage has been qualified under the Trust Indenture Act of 1939, as amended (the "Trust Indenture Act") and you should refer to the Trust Indenture Act for the provisions that apply to the First Mortgage Bonds. In the summary below, we have included references to applicable section numbers of the Mortgage so that you can more easily locate the relevant provisions.

Provisions of a Particular Series

The First Mortgage Bonds may from time to time, be issued in one or more series. You should consult the prospectus supplement or any free writing prospectus relating to any particular issue of the First Mortgage Bonds for the following information:

- the designation, series and aggregate principal amount of the First Mortgage Bonds;
- the percentage of the principal amount for which we will issue and sell the First Mortgage Bonds;
- the date of maturity for the First Mortgage Bonds;
- the rate at which the First Mortgage Bonds will bear interest or the method of determining that rate;
- the dates on which interest is payable;
- the denominations in which we will authorize the First Mortgage Bonds to be issued, if other than $1,000 or integral multiples of $1,000;
- whether we will offer the First Mortgage Bonds in the form of global bonds and, if so, the name of the depositary for any global bonds;
- the terms applicable to any rights to convert First Mortgage Bonds into or exchange them for other of our securities or those of any other entity;
- redemption terms and sinking fund provisions, if any; and
- any other specific terms that do not conflict with the Mortgage.

For more information, see Section 2.01 of the Mortgage.

No series of the First Mortgage Bonds will be limited in aggregate principal amount except as provided in the Mortgage. Unless the applicable prospectus supplement or any free writing prospectus states otherwise, the

covenants contained in the Mortgage will not afford holders of the First Mortgage Bonds protection in the event of a change of control or highly leveraged transaction.

Form and Exchanges

Unless otherwise specified in the applicable prospectus supplement or free writing prospectus, we expect to issue the First Mortgage Bonds as fully registered bonds without coupons in denominations of $1,000 or any integral multiple of $1,000. Holders may exchange them, free of charge, for a like aggregate principal amount of other First Mortgage Bonds of different authorized denominations of the same series. Holders may also transfer the First Mortgage Bonds free of charge except for any stamp taxes or other governmental charges that may apply. The First Mortgage Bonds may be presented for transfer or exchange at the corporate trust office of the Trustee in New York, New York. For more information, see Sections 2.01 and 2.03 of the Mortgage.

Interest and Payment

The prospectus supplement or free writing prospectus for any First Mortgage Bonds will state the interest rate, the method of determination of the interest rate, and the date on which interest is payable. Unless the prospectus supplement states otherwise, principal and interest on First Mortgage Bonds held in (i) definitive or certificated form will be paid at the corporate trust office of the Mortgage Trustee in New York, New York, and (ii) global form will be paid as set forth herein under "Global Securities."

Pursuant to the Mortgage, we will pay interest, to the extent enforceable under law, on any overdue installment of interest on the First Mortgage Bonds at the highest rate of interest payable on any of the First Mortgage Bonds outstanding under the Mortgage. For more information, see Section 2.01 and Article X of the Mortgage.

Redemption and Purchase of First Mortgage Bonds

If the First Mortgage Bonds are redeemable, the redemption terms will appear in the prospectus supplement or free writing prospectus. We may declare redemptions on at least 30 days' notice to the holders of First Mortgage Bonds to be redeemed and to the Mortgage Trustee. We have agreed that before the redemption date we will deposit with the Mortgage Trustee a sum of money sufficient to redeem the subject First Mortgage Bonds. Our failure to make this required deposit will constitute a completed default under the Mortgage on the specified redemption date and the First Mortgage Bonds called for redemption shall immediately become due and payable. For more information, see Article VIII of the Mortgage.

First Mortgage Bonds are redeemable, in whole but not in part, on not more than 90 days' notice to holders, at a redemption price of 100% of the principal amount thereof, together with accrued interest to the date of redemption, in the event that:

- all of our outstanding common stock is acquired by some governmental body or instrumentality and we elect to redeem all First Mortgage Bonds; or
- all or substantially all the mortgaged and pledged property, constituting bondable property as defined in the Mortgage, that is then subject to the Mortgage as a first lien shall be released from the lien of the Mortgage under the provisions thereof, and available moneys held by the Mortgage Trustee, including any moneys deposited by us for the purpose, are sufficient to redeem all the First Mortgage Bonds at the redemption prices (together with accrued interest to the date of redemption) specified therein applicable to the redemption thereof upon the happening of such event.

For more information, see Section 8.08 of the Mortgage.

Maintenance Fund

The Mortgage provides that the amount expended for property additions (excluding several stated exceptions) will, at the end of each year, equal the minimum provision for depreciation, for each calendar year subsequent to December 31, 1943, and if at the end of any such year we have not expended such required amount, we will, on or before the next succeeding March 31, deposit with the Mortgage Trustee the difference in cash. Certain credits are allowed against cash so required to be deposited. During the three years immediately following a cash deposit with the Mortgage Trustee, we may at any time or from time to time withdraw cash in an amount equal to any available maintenance credit. Cash not so withdrawn shall be applied towards the payment due upon maturity or for the redemption of outstanding First Mortgage Bonds as provided in the Mortgage. For more information, see Sections 5.08 and 1.05 of the Mortgage.

We must provide the Mortgage Trustee with an annual maintenance certificate with respect to the bondable value of property additions.

The minimum provision for depreciation means an amount equal to:

- 15% of our gross operating revenues, net of the cost of electric energy purchased for resale; *less*
- an amount equal to the aggregate of the charges to operating expense for maintenance; *provided, however,*
- that the minimum provision for depreciation for any period shall not exceed the maximum provision for depreciation, as defined, for the period.

The maximum provision for depreciation shall mean as to each full calendar year, an amount equal to:

- $755,000, *plus*
- 2.25% of the sum of all property additions after January 1, 1944 up to the beginning of the subject calendar year, *less*
- 2.25% of the aggregate amount of all retirements of bondable property during the period after January 1, 1944 up to the beginning of the subject calendar year.

For periods other than a calendar year, the maximum provision for depreciation shall be based upon the maximum provision for depreciation for the calendar year ended during such period multiplied by the number of calendar months or fractions thereof included in such period and divided by 12.

As of December 31, 2007, we had a cumulative maintenance credit of approximately $8.9 billion.

Ranking and Security

The First Mortgage Bonds will be secured by the lien of the Mortgage and will rank equally with all bonds outstanding thereunder. In the opinion of our counsel, the Mortgage constitutes a first mortgage lien, subject only to permitted encumbrances and liens, on substantially all of the fixed properties owned by us except miscellaneous properties specifically excepted. In addition, after-acquired property is covered by the lien of the Mortgage, subject to existing liens at the time such property is acquired. For more information, see the Preambles and Section 2.01 of the Mortgage.

Issuance of Additional First Mortgage Bonds

First Mortgage Bonds may be issued under the Mortgage in a principal amount equal to:

- an amount not exceeding 60% of the bondable value of property additions, which term generally includes all of our tangible property that we are authorized to acquire, own and operate, that has become subject to the Mortgage and which is used in connection with the generation, purchase, transmission, distribution or sale of electricity for light, heat, power or other purposes;

- an additional aggregate principal amount not exceeding the aggregate principal amount of refundable prior lien bonds deposited with the Mortgage Trustee or judicially determined to be invalid;
- an additional aggregate principal amount not exceeding the aggregate principal amount of any outstanding First Mortgage Bonds that have been canceled or delivered for cancellation; and
- an additional aggregate principal amount equal to the amount of cash deposited with the Mortgage Trustee against the issuance of bonds.

For more information, see Sections 4.03 thorough 4.06 of the Mortgage.

As of September 30, 2008, the bondable value of property additions under the first bullet point above was approximately $2.5 billion permitting the issuance of approximately $1.5 billion of additional bonds. As of September 30, 2008, the additional aggregate principal amount of First Mortgage Bonds that could be issued based upon the amount of previously issued First Mortgage Bonds that have been canceled or delivered for cancellation under the third bullet point above was approximately $256 million. Cash deposited with the Mortgage Trustee under the fourth bullet point above may be withdrawn in an amount equal to the principal amount of any First Mortgage Bonds we would otherwise be entitled to have authenticated under any of the provisions referred to in the first three bullet points above, and may also be used for the purchase or redemption of First Mortgage Bonds which, by their terms, are redeemable. For more information, see Section 4.06 of the Mortgage.

First Mortgage Bonds may be authenticated pursuant to the first and fourth bullet points above (and in certain cases pursuant to the second and third bullet points above) only if net earnings for 12 successive months in the 15 months immediately preceding the first day of the month in which application for additional First Mortgage Bonds is made shall be at least two times the annual interest charges on the First Mortgage Bonds and prior lien bonds outstanding and to be outstanding. For more information, see Sections 4.08 and 1.06 of the Mortgage.

Restriction on Dividends

Unless otherwise stated in the prospectus supplement or free writing prospectus, in the case of First Mortgage Bonds issued under this prospectus and any accompanying prospectus supplement or free writing prospectus, and so long as any First Mortgage Bonds are outstanding, we may only pay cash dividends on our common stock, and make any other distribution to Florida Progress, our common stockholder, out of our net income subsequent to December 31, 1943. For more information, see Section 5.24 of the Mortgage.

Release and Substitution of Property

Subject to various limitations, property may be released from the lien of the Mortgage when sold or exchanged, upon the basis of:

- cash deposited with the Mortgage Trustee;
- the principal amount of any purchase money obligations pledged with the Mortgage Trustee;
- the fair value of any property additions certified to the Mortgage Trustee and acquired by us in exchange for the property to be released; or
- if non-bondable property is to be released, the fair value of property and certain securities certified to the Mortgage Trustee and acquired by us in exchange for the property to be released, less the principal amount of certain outstanding prior lien bonds.

For more information, see Section 9.03 of the Mortgage.

If all or substantially all of the mortgaged and pledged property constituting bondable property which at the time shall be subject to the lien of the Mortgage as a first lien shall be released, whether pursuant to our request or by eminent domain, then we are required to redeem all the First Mortgage Bonds and have agreed

to deposit with the Mortgage Trustee sufficient cash for that purpose. Any new property acquired to take the place of any property released shall be subjected to the lien of the Mortgage. For more information, see Sections 8.08(b), 9.03, 9.05 and 9.11 of the Mortgage.

Modification of Mortgage

The Mortgage may generally be modified with the consent of the holders of not less than 75% in aggregate principal amount of First Mortgage Bonds outstanding which would be affected by the action proposed to be taken, except no such modifications shall:

- extend the maturity of any First Mortgage Bonds, or reduce the interest rate or extend the time of payment thereof, or reduce the principal amount thereof, without the express consent of the holder of each First Mortgage Bond affected;
- reduce the percentage of holders who must consent to the modifications referred to in this section without the consent of the holders of all First Mortgage Bonds outstanding;
- permit the creation of a prior or equal lien on the pledged property; or
- deprive any First Mortgage Bond of the lien of the Mortgage.

For more information, see Section 17.02 of the Mortgage.

Default

In the event of a completed default, the Mortgage Trustee or the holders of at least 25% of the outstanding First Mortgage Bonds may declare the principal of all outstanding First Mortgage Bonds immediately due and payable. The following are defined as completed defaults in the Mortgage:

- default in the payment of principal of, and premium, if any, on any of the First Mortgage Bonds when due and payable, whether at maturity or by declaration, or otherwise;
- default continued for 60 days in the payment of any interest on any of the First Mortgage Bonds;
- default in the payment of principal or interest upon any outstanding prior lien bonds continued beyond any applicable grace period;
- certain acts of bankruptcy, insolvency or reorganization; and
- default continued for 60 days after written notice to us by the Mortgage Trustee (or to us and the Mortgage Trustee by the holders of at least 25% in principal amount of the then outstanding First Mortgage Bonds) in the observance or performance of any other covenant, agreement or condition contained in the Mortgage or in any of the First Mortgage Bonds.

For more information, see Section 10.01 of the Mortgage.

If all defaults have been cured, however, the holders of not less than a majority in aggregate principal amount of the First Mortgage Bonds then outstanding may rescind and annul the declaration and its consequences. If the Mortgage Trustee in good faith determines it to be in the interest of the holders of the First Mortgage Bonds, it may withhold notice of default, except in payment of principal, premium, if any, interest or sinking fund payments, if any, for retirement of First Mortgage Bonds. We are required by the Mortgage to report annually to the Mortgage Trustee as to the absence of default and compliance with the provisions of the Mortgage. For more information, see Sections 10.01, 10.02 and 5.23 of the Mortgage.

The holders of not less than a majority in principal amount of the First Mortgage Bonds outstanding have the right to direct the time, method and place of conducting any proceedings for any remedy available to, or conferred by the Mortgage upon, the Mortgage Trustee; *provided, however*, that the Mortgage Trustee may, if it determines in good faith that such direction would involve the Mortgage Trustee in personal liability or be

unjustly prejudicial to the rights of the non-assenting bondholders, decline to follow such direction. For more information, see Section 10.06 of the Mortgage.

Evidence to Be Furnished to the Mortgage Trustee Under the Mortgage

We may demonstrate compliance with Mortgage provisions regarding certificates and opinions by providing written statements to the Mortgage Trustee from our officers or experts we select. For instance, we may select an engineer or appraiser to provide a written statement regarding the value of property being certified or released, or an accountant regarding net earnings, or counsel regarding property titles and compliance with the Mortgage generally. In certain significant matters, applicable law requires that an accountant or engineer must be independent. For more information, see Section 314(d) of the Trust Indenture Act. We must file certificates and other papers each year and whenever certain events occur. Additionally, we must provide evidence from time to time demonstrating our compliance with the conditions and covenants under the Mortgage.

Relationship With the Mortgage Trustee

In the normal course of business, the Mortgage Trustee or its affiliates may, from time to time, provide certain commercial banking, investment banking, and securities underwriting services to us and our affiliates. The Mortgage Trustee's affiliate currently serves as Debt Securities Trustee under our Debt Securities Indenture described below.

DESCRIPTION OF DEBT SECURITIES

General

The Debt Securities offered by this prospectus will be our direct unsecured general obligations. This prospectus describes certain general terms of the Debt Securities offered through this prospectus. When we offer to sell a particular series of Debt Securities, we will describe the specific terms of that series in a prospectus supplement or any free writing prospectus. The Debt Securities will be issued under the Indenture (for Debt Securities), dated as of December 7, 2005, between us and The Bank of New York Mellon Trust Company, National Association, as successor trustee, or one or more additional indentures for Debt Securities between us and a trustee elected by us. The Indenture (for Debt Securities) is incorporated by reference into the registration statement of which this prospectus is a part. The form of any additional indenture, between us and a trustee which we will name, under which we may issue Debt Securities is filed as an exhibit to the registration statement. In this prospectus we refer to each of the Indenture (for Debt Securities) and the form of indenture for Debt Securities, as applicable, as the "Debt Securities Indenture." We refer to the trustee under any Debt Securities Indenture as the "Debt Securities Trustee."

The prospectus supplement or any free writing prospectus applicable to a particular series of Debt Securities may state that a particular series of Debt Securities will be our subordinated obligations. The form of Debt Securities Indenture referred to above includes optional provisions (designated by brackets ("[ ]")) that we would expect to appear in a separate indenture for subordinated debt securities in the event we issue subordinated debt securities. In the following discussion, we refer to any subordinated obligations as the "Subordinated Debt Securities." Unless the applicable prospectus supplement or any free writing prospectus provides otherwise, we will use a separate Debt Securities Indenture for any Subordinated Debt Securities that we may issue. The Indenture (For Debt Securities) dated as of December 7, 2005 has been, and any future Debt Securities Indenture will be, qualified under the Trust Indenture Act and you should refer to the Trust Indenture Act for the provisions that apply to the Debt Securities.

We have summarized selected provisions of the Debt Securities Indenture below. Each Debt Securities Indenture will be independent of any other Debt Securities Indenture unless otherwise stated in a prospectus supplement or any free writing prospectus. The summary that follows is not complete and the summary is qualified in its entirety by reference to the provisions of the applicable Debt Securities Indenture. You should consult the applicable Debt Securities, Debt Securities Indenture, any supplemental indentures, officers'

certificates and other related documents for more complete information on the Debt Securities. These documents appear as exhibits to, or are incorporated by reference into, the registration statement of which this prospectus is a part, or will appear as exhibits to other documents that we will file with the SEC, which will be incorporated by reference into this prospectus. In the summary below, we have included references to applicable section numbers of the Debt Securities Indenture so that you can easily locate these provisions.

Ranking

Our Debt Securities that are not designated Subordinated Debt Securities will be effectively subordinated to all of our currently outstanding and future First Mortgage Bonds to the extent of the value of the collateral securing such First Mortgage Bonds. The First Mortgage Bond holders have a first lien on substantially all of our assets. Our Debt Securities that are designated Subordinated Debt Securities will be subordinate to all of our currently outstanding and future First Mortgage Bonds and Debt Securities that are not designated Subordinated Debt Securities. As of September 30, 2008, we had an aggregate principal amount of $4.0 billion First Mortgage Bonds outstanding and an aggregate principal amount of $150 million of unsecured indebtedness outstanding, none of which were Subordinated Debt Securities. The Indenture (For Debt Securities) does not limit the amount of First Mortgage Bonds that we may issue.

Provisions of a Particular Series

The Debt Securities may from time to time be issued in one or more series. You should consult the prospectus supplement or free writing prospectus relating to any particular series of Debt Securities for the following information:

- the title of the Debt Securities;
- any limit on aggregate principal amount of the Debt Securities or the series of which they are a part;
- the date(s), or method for determining the date(s), on which the principal of the Debt Securities will be payable;
- the rate, including the method of determination if applicable, at which the Debt Securities will bear interest, if any, and
  - — the date from which any interest will accrue;
  - — the dates on which we will pay interest;
  - — our ability to defer interest payments and any related restrictions during any interest deferral period; and
  - — the record date for any interest payable on any interest payment date;
- the place where
  - — the principal of, premium, if any, and interest on the Debt Securities will be payable;
  - — you may register transfer of the Debt Securities;
  - — you may exchange the Debt Securities; and
  - — you may serve notices and demands upon us regarding the Debt Securities;
- the security registrar for the Debt Securities and whether the principal of the Debt Securities is payable without presentment or surrender of them;
- the terms and conditions upon which we may elect to redeem any Debt Securities, including any replacement capital or similar covenants limiting our ability to redeem any Subordinated Debt Securities;

- the denominations in which we may issue Debt Securities, if other than $1,000 and integral multiples of $1,000;
- the terms and conditions upon which the Debt Securities must be redeemed or purchased due to our obligations pursuant to any sinking fund or other mandatory redemption or tender provisions, or at the holder's option, including any applicable exceptions to notice requirements;
- the currency, if other than United States currency, in which payments on the Debt Securities will be payable;
- the terms according to which elections can be made by us or the holder regarding payments on the Debt Securities in currency other than the currency in which the Debt Securities are stated to be payable;
- if payments are to be made on the Debt Securities in securities or other property, the type and amount of the securities and other property or the method by which the amount shall be determined;
- the manner in which we will determine any amounts payable on the Debt Securities that are to be determined with reference to an index or other fact or event ascertainable outside the applicable indenture;
- if other than the entire principal amount, the portion of the principal amount of the Debt Securities payable upon declaration of acceleration of their maturity;
- any addition to the events of default applicable to any Debt Securities and any additions to our covenants for the benefit of the holders of the Debt Securities;
- the terms applicable to any rights to convert Debt Securities into or exchange them for other of our securities or those of any other entity;
- whether we are issuing Debt Securities as global securities, and if so,
  - any limitations on transfer or exchange rights or the right to obtain the registration of transfer;
  - any limitations on the right to obtain definitive certificates for the Debt Securities; and
  - any other matters incidental to the Debt Securities;
- whether we are issuing the Debt Securities as bearer securities;
- any limitations on transfer or exchange of Debt Securities or the right to obtain registration of their transfer, and the terms and amount of any service charge required for registration of transfer or exchange;
- any exceptions to the provisions governing payments due on legal holidays, or any variations in the definition of business day with respect to the Debt Securities;
- any collateral security, assurance, guarantee or other credit enhancement applicable to the Debt Securities; and
- any other terms of the Debt Securities not in conflict with the provisions of the applicable Debt Securities Indenture.

For more information, see Section 301 of the applicable Debt Securities Indenture.

Debt Securities may be sold at a substantial discount below their principal amount. You should consult the applicable prospectus supplement or free writing prospectus for a description of certain special United States federal income tax considerations that may apply to Debt Securities sold at an original issue discount or denominated in a currency other than dollars.

Unless the applicable prospectus supplement or free writing prospectus states otherwise, the covenants contained in the applicable indenture will not afford holders of Debt Securities protection in the event we have a change in control or are involved in a highly-leveraged transaction.

Subordination

The applicable prospectus supplement or free writing prospectus may provide that a series of Debt Securities will be Subordinated Debt Securities, subordinate and junior in right of payment to all of our Senior Indebtedness, as defined below. If so, we will issue these securities under a separate Debt Securities Indenture for Subordinated Debt Securities. For more information, see Article XV of the form of Debt Securities Indenture.

Unless the applicable prospectus supplement or free writing prospectus states otherwise, no payment of principal of, including redemption and sinking fund payments, or any premium or interest on, the Subordinated Debt Securities may be made if:

- there occur certain acts of bankruptcy, insolvency, liquidation, dissolution or other winding up of our company;
- any Senior Indebtedness is not paid when due;
- any applicable grace period with respect to other defaults with respect to any Senior Indebtedness has ended, the default has not been cured or waived and the maturity of such Senior Indebtedness has been accelerated because of the default; or
- the maturity of the Subordinated Debt Securities of any series has been accelerated because of a default and Senior Indebtedness is then outstanding.

Upon any distribution of our assets to creditors upon any dissolution, winding-up, liquidation or reorganization, whether voluntary or involuntary or in bankruptcy, insolvency, receivership or other proceedings, all principal of, and any premium and interest due or to become due on, all outstanding Senior Indebtedness must be paid in full before the holders of the Subordinated Debt Securities are entitled to payment. For more information, see Section 1502 of the applicable Debt Securities Indenture. The rights of the holders of the Subordinated Debt Securities will be subrogated to the rights of the holders of Senior Indebtedness to receive payments or distributions applicable to Senior Indebtedness until all amounts owing on the Subordinated Debt Securities are paid in full. For more information, see Section 1504 of the applicable Debt Securities Indenture.

Unless the applicable prospectus supplement or free writing prospectus states otherwise, the term "Senior Indebtedness" means:

- all obligations (other than non-recourse obligations and the indebtedness issued under the Subordinated Debt Securities Indenture) of, or guaranteed or assumed by, us:
  - for borrowed money (including both senior and subordinated indebtedness for borrowed money, but excluding the Subordinated Debt Securities);
  - for the payment of money relating to any lease that is capitalized on our consolidated balance sheet in accordance with generally accepted accounting principles; or
  - indebtedness evidenced by bonds, debentures, notes or other similar instruments.

In the case of any such indebtedness or obligations, Senior Indebtedness includes amendments, renewals, extensions, modifications and refundings, whether existing as of the date of the Subordinated Debt Securities Indenture or subsequently incurred by us.

The Subordinated Debt Securities Indenture does not limit the aggregate amount of Senior Indebtedness that we may issue.

Form, Exchange and Transfer

Unless the applicable prospectus supplement or free writing prospectus states otherwise, we will issue Debt Securities only in fully registered form without coupons and in denominations of $1,000 and integral multiples of that amount. For more information, see Sections 201 and 302 of the applicable Debt Securities Indenture.

Holders may present Debt Securities for exchange or for registration of transfer, duly endorsed or accompanied by a duly executed instrument of transfer, at the office of the security registrar or at the office of any transfer agent we may designate. Exchanges and transfers are subject to the terms of the applicable indenture and applicable limitations for global securities. We may designate ourselves the security registrar.

No charge will be made for any registration of transfer or exchange of Debt Securities, but we may require payment of a sum sufficient to cover any tax or other governmental charge that the holder must pay in connection with the transaction. Any transfer or exchange will become effective upon the security registrar or transfer agent, as the case may be, being satisfied with the documents of title and identity of the person making the request. For more information, see Section 305 of the applicable Debt Securities Indenture.

The applicable prospectus supplement or free writing prospectus will state the name of any transfer agent, in addition to the security registrar initially designated by us, for any Debt Securities. We may at any time designate additional transfer agents or withdraw the designation of any transfer agent or make a change in the office through which any transfer agent acts. We must, however, maintain a transfer agent in each place of payment for the Debt Securities of each series. For more information, see Section 602 of the applicable Debt Securities Indenture.

We will not be required to:

- issue, register the transfer of, or exchange any Debt Securities or any tranche of any Debt Securities during a period beginning at the opening of business 15 days before the day of mailing of a notice of redemption of any Debt Securities called for redemption and ending at the close of business on the day of mailing; or
- register the transfer of, or exchange any Debt Securities selected for redemption except the unredeemed portion of any Debt Securities being partially redeemed.

For more information, see Section 305 of the applicable Debt Securities Indenture.

Payment and Paying Agents

Unless the applicable prospectus supplement or free writing prospectus states otherwise, we will pay interest on a Debt Security on any interest payment date to the person in whose name the Debt Security is registered at the close of business on the regular record date for the interest payment. For more information, see Section 307 of the applicable Debt Securities Indenture.

Unless the applicable prospectus supplement or free writing prospectus provides otherwise, we will pay principal and any premium and interest on Debt Securities at the office of the paying agent whom we will designate for this purpose. Unless the applicable prospectus supplement or free writing prospectus states otherwise, the corporate trust office of the Debt Securities Trustee in New York City will be designated as our sole paying agent for payments with respect to Debt Securities of each series. Any other paying agents initially designated by us for the Debt Securities of a particular series will be named in the applicable prospectus supplement or free writing prospectus. We may at any time add or delete paying agents or change the office through which any paying agent acts. We must, however, maintain a paying agent in each place of payment for the Debt Securities of a particular series. For more information, see Section 602 of the applicable Debt Securities Indenture.

All money we pay to a paying agent for the payment of the principal and any premium or interest on any Debt Security that remains unclaimed at the end of two years after payment is due will be repaid to us. After that date, the holder of that Debt Security shall be deemed an unsecured general creditor and may look only to us for these payments. For more information, see Section 603 of the applicable Debt Securities Indenture.

Redemption

You should consult the applicable prospectus supplement or free writing prospectus for any terms regarding optional or mandatory redemption of Debt Securities. Except for any provisions in the applicable prospectus supplement or free writing prospectus regarding Debt Securities redeemable at the holder's option, Debt Securities may be redeemed only upon notice by mail not less than 30 nor more than 60 days prior to the redemption date. Further, if less than all of the Debt Securities of a series, or any tranche of a series, are to be redeemed, the Debt Securities to be redeemed will be selected by the method provided for the particular series. In the absence of a selection provision, the Debt Securities Trustee will select a fair and appropriate method of selection. For more information, see Sections 403 and 404 of the applicable Debt Securities Indenture.

A notice of redemption we provide may state:

- that redemption is conditioned upon receipt by the paying agent on or before the redemption date of money sufficient to pay the principal of and any premium and interest on the Debt Securities; and
- that if the money has not been received, the notice will be ineffective and we will not be required to redeem the Debt Securities.

For more information, see Section 404 of the applicable Debt Securities Indenture.

Consolidation, Merger and Sale of Assets

We may not consolidate with or merge into any other person, nor may we transfer or lease substantially all of our assets and property to any person, unless:

- the corporation formed by the consolidation or into which we are merged, or the person that acquires by conveyance or transfer, or that leases, substantially all of our property and assets:
  - — is organized and validly existing under the laws of any domestic jurisdiction; and
  - — expressly assumes by supplemental indenture our obligations on the Debt Securities and under the applicable indentures;
- immediately after giving effect to the transaction, no event of default, and no event that would become an event of default, has occurred and is continuing; and
- we have delivered to the Debt Securities Trustee an officer's certificate and opinion of counsel as provided in the applicable indentures.

For more information, see Section 1101 of the applicable Debt Securities Indenture.

Events of Default

Unless the applicable prospectus supplement or free writing prospectus states otherwise, "event of default" under the applicable indenture with respect to Debt Securities of any series means any of the following:

- failure to pay any interest due on any Debt Security of that series within 30 days;
- failure to pay principal or premium, if any, when due on any Debt Security of that series;
- failure to make any required sinking fund payment on any Debt Securities of that series;

- breach of or failure to perform any other covenant or warranty in the applicable indenture with respect to Debt Securities of that series for 60 days (subject to extension under certain circumstances for another 120 days) after we receive notice from the Debt Securities Trustee, or we and the Debt Securities Trustee receive notice from the holders of at least 33% in principal amount of the Debt Securities of that series outstanding under the applicable indenture according to the provisions of the applicable indenture;
- certain events of bankruptcy, insolvency or reorganization; and
- any other event of default set forth in the applicable prospectus supplement or free writing prospectus.

For more information, see Section 801 of the applicable Debt Securities Indenture.

An event of default with respect to a particular series of Debt Securities does not necessarily constitute an event of default with respect to the Debt Securities of any other series issued under the applicable indenture.

If an event of default with respect to a particular series of Debt Securities occurs and is continuing, either the Debt Securities Trustee or the holders of at least 33% in principal amount of the outstanding Debt Securities of that series may declare the principal amount of all of the Debt Securities of that series to be due and payable immediately. If the Debt Securities of that series are discount securities or similar Debt Securities, only the portion of the principal amount as specified in the applicable prospectus supplement or free writing prospectus may be immediately due and payable. If an event of default occurs and is continuing with respect to all series of Debt Securities issued under a Debt Securities Indenture, including all events of default relating to bankruptcy, insolvency or reorganization, the Debt Securities Trustee or the holders of at least 33% in principal amount of the outstanding Debt Securities of all series issued under that Debt Securities Indenture, considered together, may declare an acceleration of the principal amount of all series of Debt Securities issued under that Debt Securities Indenture. There is no automatic acceleration, even in the event of our bankruptcy or insolvency.

The applicable prospectus supplement or free writing prospectus may provide, with respect to a series of Debt Securities to which a credit enhancement is applicable, that the provider of the credit enhancement may, if a default has occurred and is continuing with respect to the series, have all or any part of the rights with respect to remedies that would otherwise have been exercisable by the holder of that series.

At any time after a declaration of acceleration with respect to the Debt Securities of a particular series, and before a judgment or decree for payment of the money due has been obtained, the event of default giving rise to the declaration of acceleration will, without further action, be deemed to have been waived, and the declaration and its consequences will be deemed to have been rescinded and annulled, if:

- we have paid or deposited with the Debt Securities Trustee a sum sufficient to pay:
  - all overdue interest on all Debt Securities of the particular series;
  - the principal of and any premium on any Debt Securities of that series that have become due otherwise than by the declaration of acceleration and any interest at the rate prescribed in the Debt Securities;
  - interest upon overdue interest at the rate prescribed in the Debt Securities, to the extent payment is lawful; and
  - all amounts due to the Debt Securities Trustee under the applicable indenture; and
- any other event of default with respect to the Debt Securities of the particular series, other than the failure to pay the principal of the Debt Securities of that series that has become due solely by the declaration of acceleration, has been cured or waived as provided in the applicable indenture.

For more information, see Section 802 of the applicable Debt Securities Indenture.

The applicable Debt Securities Indenture includes provisions as to the duties of the Debt Securities Trustee in case an event of default occurs and is continuing. Consistent with these provisions, the Debt Securities Trustee will be under no obligation to exercise any of its rights or powers at the request or direction of any of the holders unless those holders have offered to the Debt Securities Trustee reasonable indemnity against the costs, expenses and liabilities that may be incurred by it in compliance with such request or direction. For more information, see Section 903 of the applicable Debt Securities Indenture. Subject to these provisions for indemnification, the holders of a majority in principal amount of the outstanding Debt Securities of any series may direct the time, method and place of conducting any proceeding for any remedy available to the Debt Securities Trustee, or exercising any trust or power conferred on the Debt Securities Trustee, with respect to the Debt Securities of that series. For more information, see Section 812 of the applicable Debt Securities Indenture.

No holder of Debt Securities may institute any proceeding regarding the applicable indenture, or for the appointment of a receiver or a trustee, or for any other remedy under the applicable indenture unless:

- the holder has previously given to the Debt Securities Trustee written notice of a continuing event of default of that particular series;
- the holders of a majority in principal amount of the outstanding Debt Securities of all series with respect to which an event of default is continuing have made a written request to the Debt Securities Trustee, and have offered reasonable indemnity to the Debt Securities Trustee, to institute the proceeding as trustee; and
- the Debt Securities Trustee has failed to institute the proceeding, and has not received from the holders of a majority in principal amount of the outstanding Debt Securities of that series a direction inconsistent with the request, within 60 days after notice, request and offer of reasonable indemnity.

For more information, see Section 807 of the applicable Debt Securities Indenture.

The preceding limitations do not apply, however, to a suit instituted by a holder of a Debt Security for the enforcement of payment of the principal of or any premium or interest on the Debt Securities on or after the applicable due date stated in the Debt Securities. For more information, see Section 808 of the applicable Debt Securities Indenture.

We must furnish annually to the Debt Securities Trustee a statement by an appropriate officer as to that officer's knowledge of our compliance with all conditions and covenants under each of the indentures for Debt Securities. Our compliance is to be determined without regard to any grace period or notice requirement under the respective indenture. For more information, see Section 606 of the applicable Debt Securities Indenture.

Modification and Waiver

We and the Debt Securities Trustee, without the consent of the holders of the Debt Securities, may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the assumption by any permitted successor of our covenants in the applicable indenture and the Debt Securities;
- to add one or more covenants or other provisions for the benefit of the holders of outstanding Debt Securities or to surrender any right or power conferred upon us by the applicable indenture;
- to add any additional events of default;
- to change or eliminate any provision of the applicable indenture or add any new provision to it, but if this action would adversely affect the interests of the holders of any particular series of Debt Securities in any material respect, the action will not become effective with respect to that series while any Debt Securities of that series remain outstanding under the applicable indenture;
- to provide collateral security for the Debt Securities;

- to establish the form or terms of Debt Securities according to the provisions of the applicable indenture;
- to evidence the acceptance of appointment of a successor Debt Securities Trustee under the applicable indenture with respect to one or more series of the Debt Securities and to add to or change any of the provisions of the applicable indenture as necessary to provide for trust administration under the applicable indenture by more than one trustee;
- to provide for the procedures required to permit the use of a non-certificated system of registration for any series of Debt Securities;
- to change any place where:
  - the principal of and any premium and interest on any Debt Securities are payable;
  - any Debt Securities may be surrendered for registration of transfer or exchange; or
  - notices and demands to or upon us regarding Debt Securities and the applicable indentures may be served; or
- to cure any ambiguity or inconsistency, but only by means of changes or additions that will not adversely affect the interests of the holders of Debt Securities of any series in any material respect.

For more information, see Section 1201 of the applicable Debt Securities Indenture.

The holders of at least a majority in aggregate principal amount of the outstanding Debt Securities of any series may waive:

- compliance by us with certain provisions of the applicable indenture (see Section 607 of the applicable Debt Securities Indenture); and
- any past default under the applicable indenture, except a default in the payment of principal, premium, or interest and certain covenants and provisions of the applicable indenture that cannot be modified or amended without consent of the holder of each outstanding Debt Security of the series affected (see Section 813 of the applicable Debt Securities Indenture).

The Trust Indenture Act of 1939 may be amended after the date of the applicable indenture to require changes to the indenture. In this event, the indenture will be deemed to have been amended so as to effect the changes, and we and the Debt Securities Trustee may, without the consent of any holders, enter into one or more supplemental indentures to evidence or effect the amendment. For more information, see Section 1201 of the applicable Debt Securities Indenture.

Except as provided in this section, the consent of the holders of a majority in aggregate principal amount of the outstanding Debt Securities issued pursuant to a Debt Securities Indenture, considered as one class, is required to change in any manner the applicable indenture pursuant to one or more supplemental indentures. If less than all of the series of Debt Securities outstanding under a Debt Securities Indenture are directly affected by a proposed supplemental indenture, however, only the consent of the holders of a majority in aggregate principal amount of the outstanding Debt Securities of all series directly affected, considered as one class, will be required. Furthermore, if the Debt Securities of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of one or more, but not all, tranches, only the consent of the holders of a majority in aggregate principal amount of the outstanding Debt Securities of all tranches directly affected, considered as one class, will be required. In addition, an amendment or modification:

- may not, without the consent of the holder of each outstanding Debt Security affected:
  - change the maturity of the principal of, or any installment of principal of or interest on, any Debt Securities;

- reduce the principal amount or the rate of interest, or the amount of any installment of interest, or change the method of calculating the rate of interest;
- reduce any premium payable upon the redemption of the Debt Securities;
- reduce the amount of the principal of any Debt Security originally issued at a discount from the stated principal amount that would be due and payable upon a declaration of acceleration of maturity;
- change the currency or other property in which a Debt Security or premium or interest on a Debt Security is payable; or
- impair the right to institute suit for the enforcement of any payment on or after the stated maturity, or in the case of redemption, on or after the redemption date, of any Debt Securities;

- may not reduce the percentage of principal amount requirement for consent of the holders for any supplemental indenture, or for any waiver of compliance with any provision of or any default under the applicable indenture, or reduce the requirements for quorum or voting, without the consent of the holder of each outstanding Debt Security of each series or tranche affected; and
- may not modify provisions of the applicable indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to the Debt Securities of any series, or any tranche of a series, without the consent of the holder of each outstanding Debt Security affected.

A supplemental indenture will be deemed not to affect the rights under the applicable indenture of the holders of any series or tranche of the Debt Securities if the supplemental indenture:

- changes or eliminates any covenant or other provision of the applicable indenture expressly included solely for the benefit of one or more other particular series of Debt Securities or tranches thereof; or
- modifies the rights of the holders of Debt Securities of any other series or tranches with respect to any covenant or other provision.

For more information, see Section 1202 of the applicable Debt Securities Indenture.

If we solicit from holders of the Debt Securities any type of action, we may at our option by board resolution fix in advance a record date for the determination of the holders entitled to vote on the action. We shall have no obligation, however, to do so. If we fix a record date, the action may be taken before or after the record date, but only the holders of record at the close of business on the record date shall be deemed to be holders for the purposes of determining whether holders of the requisite proportion of the outstanding Debt Securities have authorized the action. For that purpose, the outstanding Debt Securities shall be computed as of the record date. Any holder action shall bind every future holder of the same security and the holder of every security issued upon the registration of transfer of or in exchange for or in lieu of the security in respect of anything done or permitted by the Debt Securities Trustee or us in reliance on that action, whether or not notation of the action is made upon the security. For more information, see Section 104 of the applicable Debt Securities Indenture.

Defeasance

Unless the applicable prospectus supplement or free writing prospectus provides otherwise, any Debt Security, or portion of the principal amount of a Debt Security, will be deemed to have been paid for purposes of the applicable indenture, and, at our election, our entire indebtedness in respect of the Debt Security, or portion thereof, will be deemed to have been satisfied and discharged, if we have irrevocably deposited with the Debt Securities Trustee or any paying agent other than us, in trust money, certain eligible obligations, as defined in the applicable indenture, or a combination of the two, sufficient to pay principal of and any premium and interest due

and to become due on the Debt Security or portion thereof. For more information, see Section 701 of the applicable Debt Securities Indenture. For this purpose, unless the applicable prospectus supplement or free writing prospectus provides otherwise, eligible obligations include direct obligations of, or obligations unconditionally guaranteed by, the United States, entitled to the benefit of full faith and credit of the United States, and certificates, depositary receipts or other instruments that evidence a direct ownership interest in those obligations or in any specific interest or principal payments due in respect of those obligations.

Resignation, Removal of Debt Securities Trustee; Appointment of Successor

The Debt Securities Trustee may resign at any time by giving written notice to us or may be removed at any time by an action of the holders of a majority in principal amount of outstanding Debt Securities delivered to the Debt Securities Trustee and us. No resignation or removal of the Debt Securities Trustee and no appointment of a successor trustee will become effective until a successor trustee accepts appointment in accordance with the requirements of the applicable indenture. So long as no event of default or event that would become an event of default has occurred and is continuing, and except with respect to a Debt Securities Trustee appointed by an action of the holders, if we have delivered to the Debt Securities Trustee a resolution of our board of directors appointing a successor trustee and the successor trustee has accepted the appointment in accordance with the terms of the applicable indenture, the Debt Securities Trustee will be deemed to have resigned and the successor trustee will be deemed to have been appointed as trustee in accordance with the applicable indenture. For more information, see Section 910 of the applicable Debt Securities Indenture.

Notices

We will give notices to holders of Debt Securities by mail to their addresses as they appear in the Debt Security Register. For more information, see Section 106 of the applicable Debt Securities Indenture.

Title

The Debt Securities Trustee and its agents, and we and our agents, may treat the person in whose name a Debt Security is registered as the absolute owner of that Debt Security, whether or not that Debt Security may be overdue, for the purpose of making payment and for all other purposes. For more information, see Section 308 of the applicable Debt Securities Indenture.

Governing Law

The Debt Securities Indentures and the Debt Securities, including any Subordinated Debt Securities Indentures and Subordinated Debt Securities, will be governed by, and construed in accordance with, the law of the State of New York. For more information, see Section 112 of the applicable Debt Securities Indenture.

Relationship With the Current Trustee or Future Trustees

In the normal course of business, the Trustee under our Indenture (For Debt Securities), dated as of December 7, 2005, or its affiliates provides, and any future trustee or its affiliates may, from time to time, provide certain commercial banking, investment banking, and securities underwriting services to us and our affiliates. The Debt Securities Trustee's affiliate currently serves as Mortgage Trustee under our Mortgage described above.

DESCRIPTION OF PREFERRED STOCK

The following summary of the characteristics of our preferred stock is a summary and is qualified in all respects by reference to our amended articles of incorporation and bylaws, each as amended, copies of which are filed as exhibits to the registration statement of which this prospectus is a part. You should carefully read each of these documents in order to fully understand the terms and provisions of our preferred stock.

Reference is also made to the laws of the State of Florida.

General

Our authorized preferred stock consists of the following classes with the following number of authorized shares per class:

- Cumulative Preferred Stock —4,000,000 shares with a par value of $100 per share; and
- Cumulative Preferred Stock —5,000,000 shares with no par value.

Our board of directors may authorize the preferred stock to be issued from time to time as one or more series of preferred stock. For each new series of preferred stock, the board of directors, within the limitations and restrictions stated in Article III(B) of our articles of incorporation, may establish the number of shares in each series and to fix the designation, powers, preferences and rights of each such series and the qualifications, limitations or restrictions thereof. Generally, each class of our preferred stock ranks equally with each other class and senior to our preference stock and our common stock.

$100 Cumulative Preferred Stock

Our articles of incorporation authorize 4,000,000 shares of Cumulative Preferred Stock with a par value of $100 per share ("$100 Cumulative Preferred Stock"). We have the following five designated series of $100 Cumulative Preferred Stock with the corresponding number of authorized and outstanding shares as of September 30, 2008: (i) 40,000 shares of 4.00% Series authorized, 39,980 shares outstanding; (ii) 40,000 shares of 4.60% Series authorized, 39,997 shares outstanding; (iii) 80,000 shares of 4.75% Series authorized and outstanding; (iv) 75,000 shares of 4.40% Series authorized and outstanding; and (v) 100,000 shares of 4.58% Series authorized, 99,990 shares outstanding. All of our other previously designated series of $100 Cumulative Preferred Stock have been redeemed or retired. The terms of the $100 Cumulative Preferred Stock generally include:

- cumulative quarterly dividends of a rate fixed by the board of directors at the time the series is issued. Currently, the five separate series of outstanding $100 Cumulative Preferred Stock have the following dividend rates:
  - $100 Cumulative Preferred Stock, 4.00% Series —4.00% per annum;
  - $100 Cumulative Preferred Stock, 4.60% Series —4.60% per annum;
  - $100 Cumulative Preferred Stock, 4.75% Series —4.75% per annum;
  - $100 Cumulative Preferred Stock, 4.40% Series —4.40% per annum; and
  - $100 Cumulative Preferred Stock, 4.58% Series —4.58% per annum;
- a liquidation preference, which may vary depending on whether the liquidation is voluntary or involuntary. The holders of each series of $100 Cumulative Preferred Stock will be entitled to receive: (i) in the event of an involuntary liquidation, the par or stated value of the shares of the series, plus all accrued and unpaid dividends; or (ii) in the event of a voluntary liquidation, the redemption price fixed by the board of directors at the time the series was issued, or in the event the shares of a particular series are not then redeemable, the amount specified in the foregoing clause (i); and

- redemption rights at a price per share fixed by the board of directors at the time the series is issued. Currently, the five separate series of outstanding $100 Cumulative Preferred Stock have the following redemption prices:
  - $100 Cumulative Preferred Stock, 4.00% Series —$104.25 per share, plus accrued and unpaid dividends;
  - $100 Cumulative Preferred Stock, 4.60% Series —$103.25 per share, plus accrued and unpaid dividends;
  - $100 Cumulative Preferred Stock, 4.75% Series —$102.00 per share, plus accrued and unpaid dividends;
  - $100 Cumulative Preferred Stock, 4.40% Series —$102.00 per share, plus accrued and unpaid dividends; and
  - $100 Cumulative Preferred Stock, 4.58% Series —$101.00 per share, plus accrued and unpaid dividends.

No Par Cumulative Preferred Stock

Our articles of incorporation authorize 5,000,000 shares of Cumulative Preferred Stock with no par value ("No Par Cumulative Preferred Stock"), none of which were outstanding as of September 30, 2008. The terms of the No Par Cumulative Preferred Stock generally include:

- cumulative quarterly dividends of a rate fixed by the board of directors at the time the series is issued; and
- a liquidation preference, which may vary depending on whether the liquidation is voluntary or involuntary. The holders of each series of No Par Cumulative Preferred Stock will be entitled to receive: (i) in the event of an involuntary liquidation, the par or stated value of the shares of the series, plus all accrued and unpaid dividends; or (ii) in the event of a voluntary liquidation, the redemption price fixed by the board of directors at the time the series was issued, or in the event the shares of a particular series are not then redeemable, the amount specified in the foregoing clause (i).

Prior to the issuance of any shares of No Par Cumulative Preferred Stock, the board of directors shall establish a stated value for the shares of each series. This stated value cannot exceed the lesser of $100 per share or the consideration to be received for each share.

Certain Voting Rights of Preferred Stock Holders

Holders of our preferred stock do not have a right to vote in elections of directors or on any other matter, except as required by law or as specifically required under our amended articles of incorporation. In the event that we have not made distributions with respect to any of our preferred stock for a period of at least four quarters, until all dividends accumulated through the current dividend period have been paid, our articles of incorporation permit the holders of our preferred stock to elect a majority of the directors to our board of directors. Additionally, our amended articles of incorporation permit the holders of our preferred stock to vote on certain amendments to our amended articles of incorporation that materially and adversely affect the rights, preferences or privileges of the preferred stock. When entitled to vote, each share of our $100 Cumulative Preferred Stock and No Par Cumulative Preferred Stock having a stated value of $100 per share is generally entitled to one vote per share, while each share of No Par Cumulative Preferred Stock having a stated value less than $100 per share is generally entitled to that fraction of a vote per share equal to the quotient of a fraction, the numerator of which is the stated value of the share and the denominator of which is $100. In the event the holders of our preferred stock acquire the right to elect directors as set forth above, such holders are entitled to cumulate their votes in the election of the directors.

Dividend Restrictions and Certain Covenants

Unless dividends on all outstanding shares of each series of our preferred stock shall have been paid, or declared and set aside for payment, we cannot:

- pay or declare dividends (other than dividends payable in common stock or any other stock subordinate to our preferred stock) on, or make any other distribution on, our common stock or any other stock subordinate to our preferred stock; or
- purchase or otherwise acquire for value our common stock or any other stock subordinate to our preferred stock.

So long as any shares of our preferred stock are outstanding, we cannot pay any dividends on (other than dividends payable in common stock or any other stock subordinate to our preferred stock), make any distribution on, or purchase or otherwise acquire for value, any of our common stock or other stock subordinate to our preferred stock, if after giving effect to such dividend, distribution or purchase, the aggregate amount of such dividends, distributions or purchases paid or made since April 30, 1944 exceeds the sum of:

- all credits to earned surplus since April 30, 1944; and
- all amounts credited to capital surplus since April 30, 1944, arising from the donation of cash or securities (other than securities junior to our preferred stock as to assets and dividends) to us or transfers of amounts from earned surplus to capital surplus.

In addition, so long as any shares of our preferred stock are outstanding:

- if and so long as our common stock equity (as defined below) at the end of the calendar month immediately preceding the date on which a dividend on our common stock is declared is, or as a result of such dividend would become, less than 20% of our total capitalization (as defined below), we shall not declare dividends on our common stock in an amount which, together with all other dividends on our common stock declared within the year ending on the date of such dividend declaration, exceeds 50% of the net income of the corporation available for dividends on common stock (as defined below) for the 12 months immediately preceding the month in which such dividend is declared;
- if and so long as our common stock equity at the end of the calendar month immediately preceding the date on which a dividend on our common stock is declared is, or as a result of such dividend would become, less than 25%, but not less than 20%, of our total capitalization, we shall not declare dividends on our common stock in an amount which, together with all other dividends on our common stock declared within the year ending on the date of such dividend declaration, exceeds 75% of the net income of the corporation available for dividends on common stock for the 12 months immediately preceding the month in which such dividend is declared; and
- at any time when our common stock equity is 25% or more of total capitalization, we may not pay dividends on shares of our common stock which would reduce common stock equity below 25% of total capitalization; *provided, however*, that even though the payment of such dividends would reduce our common stock equity below 25% of total capitalization, we may declare such dividends to the extent that the same, together with all dividends on our common stock declared within the year ending on the date of such dividend declaration do not exceed 75% of our net income available for dividends on common stock for the 12 months immediately preceding the month in which such dividends are declared.

So long as any shares of our preferred stock are outstanding, we cannot, without the consent of the holders of the shares of our preferred stock entitled to cast at least two-thirds of the votes thereon:

- create or authorize any kind of stock ranking prior to or on a parity with any of our preferred stock as to assets or dividends, or create or authorize any security convertible into shares of such stock; or

- amend, alter, change or repeal any of the terms of any of our preferred stock then outstanding in a manner prejudicial to the holders thereof; provided, however, that if any such amendment, alteration, change or repeal would be prejudicial to the holders of shares of one or more, but not all, of the series of our preferred stock, such consent shall be required only from the holders of at least two-thirds of the series so affected.

So long as any shares of our preferred stock are outstanding, we cannot, without the consent of the holders of the shares of our preferred stock entitled to cast at least a majority of the votes thereon:

- increase the total authorized amount of our preferred stock;
- issue any shares of our preferred stock, unless for any period of 12 consecutive calendar months within the 15 calendar months immediately preceding the month of issuance:
  - — our net earnings applicable to the payment of dividends on shares of our preferred stock is at least two times the annual dividend requirements on all shares of our preferred stock to be outstanding immediately after the proposed issuance (excluding from the foregoing calculation all stock to be retired in connection with the proposed issuance); and
  - — our net earnings available for the payment of interest charges on our indebtedness is at least one and one-half times the sum of (i) the annual interest charges on our indebtedness and (ii) the annual dividend requirements on all shares of our preferred stock to be outstanding immediately after the proposed issuance (excluding from the foregoing calculation all indebtedness and stock to be retired in connection with the proposed issuance);
- issue or incur additional indebtedness maturing more than 12 months from the date of issue, or issue any additional shares of preferred stock, unless immediately after such issuance, the aggregate of the principal amount of indebtedness then maturing in more than 12 months and the par value or stated value of preferred stock then outstanding shall be less than 75% of our total capitalization;
- issue any shares of our preferred stock, unless the aggregate of our capital applicable to our common stock and our surplus is not less than the amount payable upon involuntary dissolution to the holders of our preferred stock to be outstanding immediately after the proposed issuance (excluding from the foregoing calculation stock to be retired in connection with the proposed issuance); *provided* that no portion of our surplus used to meet the requirements of the foregoing calculation shall be available for dividends or distributions upon our common stock after such issuance and until such shares or a like number of other shares of our preferred stock shall have been retired; or
- merge or consolidate with or into any other corporation; *provided* that this restriction shall not apply to a merger pursuant to any provision of law which authorizes us, without shareholder action, to be the surviving party if the terms of the merger do not alter the provisions of our amended articles of incorporation (except as to our corporate name) nor otherwise affect our outstanding shares.

As used herein under the caption "Description of Preferred Stock — Dividend Restrictions and Certain Covenants", the following terms shall have the meanings set forth below.

- The term "common stock equity" shall mean the sum of the amount of the par or stated value of the issued and outstanding shares of our common stock and the surplus (including capital or paid-in surplus) and premium on our common stock, less the amount known, or estimated if not known, to represent the excess, if any, of recorded value over original cost of used and useful utility plant and other property, and less any items set forth on the asset side of the balance sheet as a result of accounting convention such as unamortized debt discount and expense, capital stock discount and expense, and the aggregate, if any, of all accrued and unpaid dividends upon all outstanding shares of all series of our preferred stock, unless such amount or items to be deducted in the determination of common stock equity are provided for by reserves.

- The term "total capitalization" shall mean the aggregate of the par or stated value of the issued and outstanding shares of all classes of our stock and the surplus (including capital or paid-in surplus) and premium on our capital stock, plus the principal amount of all outstanding debt maturing more than 12 months from the date of the determination of total capitalization.
- The term "dividends on common stock" shall include dividends or other distributions on or the purchase or other acquisition for value of shares of our common stock, but shall not include dividends payable solely in shares of our common stock.
- The term "net income of the corporation available for dividends on capital stock" for any 12 month period shall mean an amount equal to the sum of the operating revenues and income from investments and other miscellaneous income for such period, less all accrued operating expenses for such period, including maintenance and provision for depreciation or retirements, income and excess profits and other taxes, interest charges, and amortization charges, all as shall be determined in accordance with generally accepted accounting principles, and less also current and accrued dividends on all outstanding shares of our stock ranking prior to our common stock as to dividends or assets.

Transfer Agent

The transfer agent and registrar for the 4.00% Series, 4.60% Series, 4.75% Series, 4.40% Series, and 4.58% Series of our $100 Cumulative Preferred Stock is Computershare Trust Company, N.A. The transfer agent and registrar for our other series of preferred stock will be set forth in the applicable prospectus supplement.

Future Series of Preferred Stock

Our board of directors may authorize the preferred stock to be issued from time to time as one or more series of preferred stock. All shares of preferred stock of all series shall be of equal rank and all shares of any particular series of preferred stock shall be identical, except as to the date or dates from which dividends thereon shall be cumulative. For each new series of preferred stock, the board of directors, within the limitations and restrictions stated in Article III(B) of our articles of incorporation, may establish:

- the number of shares in each series;
- the annual dividend rate;
- the date from which dividends shall be cumulative;
- the redemption price(s) (if any);
- the time(s) and the amount of shares and other terms with respect to the redemption of shares;
- any sinking fund provisions;
- the conversion, participating or other special rights; and
- the qualifications, limitations or restrictions thereof.

The terms of any future preferred stock offered will be set forth in a prospectus supplement or free writing prospectus.

GLOBAL SECURITIES

We may issue some or all of our securities of any series as global securities. We will register each global security in the name of a depositary identified in the applicable prospectus supplement. The global securities will be deposited with a depositary or nominee or custodian for the depositary and will bear a legend regarding restrictions on exchanges and registration of transfer as discussed below and any other matters to be provided pursuant to the indenture.

As long as the depositary or its nominee is the registered holder of a global security, that person will be considered the sole owner and holder of the global security and the securities represented by it for all purposes under the securities and the indenture. Except in limited circumstances, owners of a beneficial interest in a global security:

- will not be entitled to have the global security or any securities represented by it registered in their names;
- will not receive or be entitled to receive physical delivery of certificated securities in exchange for the global security; and
- will not be considered to be the owners or holders of the global security or any securities represented by it for any purposes under the securities or the indenture.

We will make all payments of principal and any premium and interest on a global security to the depositary or its nominee as the holder of the global security. The laws of some jurisdictions require that certain purchasers of securities take physical delivery of securities in definitive form. These laws may impair the ability to transfer beneficial interests in a global security.

Ownership of beneficial interests in a global security will be limited to institutions having accounts with the depositary or its nominee, called "participants" for purposes of this discussion, and to persons that hold beneficial interests through participants. When a global security is issued, the depositary will credit on its book-entry, registration and transfer system the principal amounts of securities represented by the global security to the accounts of its participants. Ownership of beneficial interests in a global security will be shown only on, and the transfer of those ownership interests will be effected only through, records maintained by:

- the depositary, with respect to participants' interests; or
- any participant, with respect to interests of persons held by the participants on their behalf.

Payments by participants to owners of beneficial interests held through the participants will be the responsibility of the participants. The depositary may from time to time adopt various policies and procedures governing payments, transfers, exchanges and other matters relating to beneficial interests in a global security. None of the following will have any responsibility or liability for any aspect of the depositary's or any participant's records relating to, or for payments made on account of, beneficial interests in a global security, or for maintaining, supervising or reviewing any records relating to those beneficial interests:

- us or our affiliates;
- the trustee under any indenture; or
- any agent of any of the above.

PLAN OF DISTRIBUTION

We may sell the securities:

- through underwriters or dealers;
- directly through a limited number of institutional or other purchasers or to a single purchaser;
- through agents; or
- by any other legal means.

The applicable prospectus supplement will set forth the terms under which the securities are offered, including:

- the names of any underwriters, dealers or agents, and the respective amounts underwritten by each;
- the purchase price and the net proceeds to us from the sale;

- any underwriting discounts and other items constituting underwriters' compensation;
- any initial public offering price;
- any discounts or concessions allowed, re-allowed or paid to dealers; and
- any securities exchanges on which we may list any offered securities.

We or any underwriters or dealers may change from time to time any initial public offering price and any discounts or concessions allowed or re-allowed or paid to dealers.

If we use underwriters in the sale, the securities will be acquired by the underwriters for their own account and may be resold in one or more transactions, including negotiated transactions, at a fixed public offering price or at varying prices determined at the time of the sale. Unless the applicable prospectus supplement states otherwise, the obligations of the underwriters to purchase the securities will be subject to certain conditions, and the underwriters will be severally obligated to purchase all of the securities, except that in certain cases involving a default by an underwriter, less than all of the securities may be purchased. If we sell securities through an agent, the applicable prospectus supplement will state the name and any commission payable by us to the agent. Unless the prospectus supplement provides otherwise, any agent acting for us will be acting on a best efforts basis for the period of its appointment.

The applicable prospectus supplement will state whether we will authorize agents, underwriters or dealers to solicit offers by certain specified institutions to purchase securities at the public offering price set forth in the prospectus supplement or free writing prospectus pursuant to delayed delivery contracts providing for payment and delivery on a specified future date. These contracts will be subject to the conditions set forth in the prospectus supplement. Additionally, the prospectus supplement or free writing prospectus will set forth the commission payable for solicitation of these contracts.

Agents and underwriters may be entitled, under agreements with us, to indemnification by us against certain civil liabilities, including liabilities under the Securities Act of 1933, as amended.

EXPERTS

The financial statements and the related financial statement schedule, incorporated in this prospectus by reference from our Current Report on Form 8-K dated November 6, 2008, for the year ended December 31, 2007 have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report (which report on the financial statements and financial statement schedule expresses an unqualified opinion and includes an explanatory paragraph concerning the retrospective adoption of a new accounting principle in 2008 and the adoption of new accounting principles in 2007 and 2006), which is incorporated herein by reference. Such financial statements and financial statement schedule have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

LEGAL MATTERS

Unless the applicable prospectus supplement provides otherwise, R. Alexander Glenn, General Counsel of Florida Power Corporation, and Hunton & Williams LLP, our outside counsel, will issue opinions about the legality of the offered securities for us. Unless the applicable prospectus supplement provides otherwise, any underwriters or agents will be advised about issues relating to any offering by their legal counsel, Dewey & LeBoeuf LLP of New York, New York. As of September 30, 2008, Mr. Glenn beneficially owned, or had options to acquire, a number of shares of our common stock, which represented less than 0.1% of the total outstanding common stock. Mr. Glenn is acquiring additional shares of Progress Energy, Inc. common stock at regular intervals as a participant in the Progress Energy 401(k) Savings & Stock Ownership Plan.

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$300,000,000

Florida Power Corporation d/b/a

Progress Energy Florida, Inc.

First Mortgage Bonds
3.10% Series due 2021

Prospectus Supplement

August 15, 2011

Joint Book-Running Managers

Barclays Capital
Citigroup
Goldman, Sachs & Co.

Co-Managers

Mitsubishi UFJ Securities
SunTrust Robinson Humphrey
KeyBanc Capital Markets
The Williams Capital Group, L.P.

EXHIBIT (4)-e

COMMERCIAL PAPER
DEALER AGREEMENT

between

Florida Power Corporation d/b/a Progress Energy Florida, Inc., as Issuer

and

RBS Securities Inc., as Dealer

Concerning Notes to be issued pursuant to an Issuing and Paying Agency Agreement dated as of May 25, 2011, as amended, between the Issuer and Morgan Guaranty Trust Company of New York (now JPMorgan Chase Bank, N.A.), as Issuing and Paying Agent

Dated as of

May 31, 2011

Commercial Paper Dealer Agreement
3(a)(3) Program

This agreement (the "Agreement") sets forth the understandings between the Issuer and the Dealer, each named on the cover page hereof, in connection with the issuance and sale by the Issuer of its short-term promissory notes (the "Notes") through the Dealer.

Certain terms used in this Agreement are defined in Section 6 hereof.

The Addendum to this Agreement, and any Annexes or Exhibits described in this Agreement or such Addendum, are hereby incorporated into this Agreement and made fully a part hereof.

1. Offers, Sales and Resales of Notes.

1.1 While (i) the Issuer has and shall have no obligation to sell the Notes to the Dealer or to permit the Dealer to arrange any sale of the Notes for the account of the Issuer, and (ii) the Dealer has and shall have no obligation to purchase the Notes from the Issuer or to arrange any sale of the Notes for the account of the Issuer, the parties hereto agree that in any case where the Dealer purchases Notes from the Issuer, or arranges for the sale of Notes by the Issuer, such Notes will be purchased or sold by the Dealer in reliance on the representations, warranties, covenants and agreements of the Issuer contained herein or made pursuant hereto and on the terms and conditions and in the manner provided herein.

1.2 So long as this Agreement shall remain in effect, the Issuer shall not, without the consent of the Dealer, offer, solicit or accept offers to purchase, or sell, any Notes or notes substantially similar to the Notes in reliance upon the exemption from registration under the Securities Act contained in Section 3(a)(3) thereof, except (a) in transactions with one or more dealers which may from time to time after the date hereof become dealers with respect to the Notes by executing with the Issuer one or more agreements, of which the Issuer hereby undertakes to provide the Dealer prompt notice, (b) in transactions with the other dealers listed on the Addendum hereto, which are executing agreements with the Issuer contemporaneously herewith, or (c) directly on its own behalf in transactions with persons other than broker-dealers with respect to which no commission is payable.

1.3 The Notes shall be in a minimum denomination of $100,000 or integral multiples of $1,000 in excess thereof, will bear such interest rates, if interest bearing, or will be sold at such discount from their face amounts, as shall be agreed upon by the Dealer and the Issuer; shall have a maturity not exceeding 270 days from the date of issuance (exclusive of days of grace); and may have such terms as are specified in Exhibit B hereto or the Offering Materials. The Notes shall not contain any provision for extension, renewal or automatic "rollover." The Notes shall be issued in the ordinary course of the Issuer's business.

1.4 The authentication and issuance of, and payment for, the Notes shall be effected in accordance with the Issuing and Paying Agency Agreement, and the Notes shall be either individual physical certificates or book-entry notes evidenced by one or more Master Notes (each, a "Master Note") registered in the name of The Depository Trust Company ("DTC") or its nominee, in the form or forms annexed to the Issuing and Paying Agency Agreement.

1.5 If the Issuer and the Dealer shall agree on the terms of the purchase of any Note by the Dealer or the sale of any Note arranged by the Dealer (including, but not limited to, agreement with respect to the date of issue, purchase price, principal amount, maturity and interest rate or interest rate index and margin (in the case of interest-bearing Notes) or discount thereof (in the case of Notes issued on a discount basis), and appropriate compensation for the Dealer's services hereunder) pursuant to this Agreement, the Issuer shall cause such Note to be issued and delivered in accordance with the terms of the Issuing and Paying Agency Agreement and payment for such Note shall be made by the purchaser thereof, either directly or through the Dealer, to the Issuing and Paying Agent, for the account of the Issuer. Except as otherwise agreed, in the event that the Dealer is acting as an agent and a purchaser shall either fail to accept delivery of or make payment for a Note on the date fixed for settlement, the Dealer shall promptly notify the Issuer, and if the Dealer has theretofore paid the Issuer for the Note, the Issuer will promptly return such funds to the Dealer against its return of the Note to the Issuer, in the case of a certificated Note, and upon notice of such failure in the case of a book-entry Note. If such failure occurred for any reason other than default by the Dealer, the Issuer shall reimburse the Dealer on an equitable basis for the Dealer's loss of the use of such funds for the period such funds were credited to the Issuer's account.

2. Representations and Warranties of Issuer.

The Issuer represents and warrants that:

2.1 The Issuer is a corporation duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has all the requisite power and authority to execute, deliver and perform its obligations under the Notes, this Agreement and the Issuing and Paying Agency Agreement.

2.2 This Agreement and the Issuing and Paying Agency Agreement have been duly authorized, executed and delivered by the Issuer and constitute legal, valid and binding obligations of the Issuer enforceable against the Issuer in accordance with their terms, subject to applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally, and subject, as to enforceability, to general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

2.3 The Notes have been duly authorized, and when issued as provided in the Issuing and Paying Agency Agreement, will be duly and validly issued and will constitute legal, valid and binding obligations of the Issuer enforceable against the Issuer in accordance with their terms, subject to applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally, and subject, as to enforceability, to general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

2.4 The Notes are not required to be registered under the Securities Act, pursuant to the exemption from registration contained in Section 3(a)(3) thereof, and no indenture in respect of the Notes is required to be qualified under the Trust Indenture Act of 1939, as amended; and the Notes are and will be rated as "prime quality" commercial paper by at least one nationally recognized statistical rating organization and will rank at least *pari passu* with all other unsecured and unsubordinated indebtedness of the Issuer.

2.5 No consent or action of, or filing or registration with, any governmental or public regulatory body or authority, including the SEC, is required to authorize, or is otherwise required in connection with the execution, delivery or performance of, this Agreement, the Notes or the Issuing and Paying Agency Agreement, except as may be required by the securities or Blue Sky laws of the various states in connection with the offer and sale of the Notes.

2.6 Neither the execution and delivery of this Agreement and the Issuing and Paying Agency Agreement, nor the issuance of the Notes in accordance with the Issuing and Paying Agency Agreement, nor the fulfillment of or compliance with the terms and provisions hereof or thereof by the Issuer, will (i) result in the creation or imposition of any mortgage, lien, charge or encumbrance of any nature whatsoever upon any of the properties or assets of the Issuer, or (ii) violate or result in a breach or a default under any of the terms of the Issuer's charter documents or by-laws, any contract or instrument to which the Issuer is a party or by which it or its property is bound, or any law or regulation, or any order, writ, injunction or decree of any court or government instrumentality, to which the Issuer is subject or by which it or its property is bound, which breach or default might have a material adverse effect on the condition (financial or otherwise), operations or business prospects of the Issuer or the ability of the Issuer to perform its obligations under this Agreement, the Notes or the Issuing and Paying Agency Agreement.

2.7 There is no litigation or governmental proceeding pending, or to the knowledge of the Issuer threatened, against or affecting the Issuer or any of its subsidiaries which might result in a material adverse change in the condition (financial or otherwise), operations or business prospects of the Issuer or the ability of the Issuer to perform its obligations under this Agreement, the Notes or the Issuing and Paying Agency Agreement.

2.8 The Issuer is not an "investment company" within the meaning of the Investment Company Act of 1940, as amended.

2.9 Neither the Offering Materials nor the Company Information contains any untrue statement of a material fact or omits to state a material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they were made, not misleading.

2.10 Each (a) issuance of Notes by the Issuer hereunder and (b) amendment or supplement of the Offering Materials shall be deemed a representation and warranty by the Issuer to the Dealer, as of the date thereof, that, both before and after giving effect to such issuance, and after giving effect to such amendment or supplement, (i) the representations and warranties given by the Issuer set forth above in this Section 2 remain true and correct on and as of such date as if made on and as of such date, (ii) in the case of an issuance of Notes, the Notes being issued on such date have been duly and validly issued and constitute legal, valid and binding obligations of the Issuer, enforceable against the Issuer in accordance with their terms, subject to applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally and subject, as to enforceability, to general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law), (iii) in the case of an issuance of Notes, since the date of the most recent Offering Materials, there has been no material adverse change in the condition (financial or otherwise), operations or business prospects of the Issuer which has not

been disclosed to the Dealer in writing and (iv) the Issuer is not in default of any of its obligations hereunder, under the Notes or under the Issuing and Paying Agency Agreement.

3. Covenants and Agreements of Issuer.

The Issuer covenants and agrees that:

3.1 The Issuer will give the Dealer prompt notice (but in any event prior to any subsequent issuance of Notes hereunder) of any amendment to, modification of or waiver with respect to, the Notes or the Issuing and Paying Agency Agreement, including a complete copy of any such amendment, modification or waiver.

3.2 The Issuer shall, whenever there shall occur any change in the Issuer's condition (financial or otherwise), operations or business prospects or any development or occurrence in relation to the Issuer that would be material to holders of the Notes or potential holders of the Notes (including any downgrading or receipt of any notice of intended or potential downgrading or any review for potential change in the rating accorded any of the Issuer's securities by any nationally recognized statistical rating organization which has published a rating of the Notes), promptly, and in any event prior to any subsequent issuance of Notes hereunder, notify the Dealer (by telephone) of such change, development or occurrence.

3.3 The Issuer shall from time to time furnish to the Dealer such information as the Dealer may reasonably request, including, without limitation, any press releases or material provided by the Issuer to any national securities exchange or rating agency, regarding (i) the Issuer's operations and financial condition, (ii) the due authorization and execution of the Notes and (iii) the Issuer's ability to pay the Notes as they mature.

3.4 The Issuer will take all such action as the Dealer may reasonably request to ensure that each offer and each sale of the Notes will comply with any applicable state Blue Sky laws; provided, however, that the Issuer shall not be obligated to file any general consent to service of process or to qualify as a foreign corporation in any jurisdiction in which it is not so qualified or subject itself to taxation in respect of doing business in any jurisdiction in which it is not otherwise so subject.

3.5 The Issuer will use the proceeds of the sale of the Notes for "current transactions" within the meaning of Section 3(a)(3) of the Securities Act.

3.6 The Issuer will not be in default of any of its obligations hereunder, under the Notes or under the Issuing and Paying Agency Agreement, at any time that any of the Notes are outstanding.

3.7 The Issuer shall not issue Notes hereunder until the Dealer shall have received (a) an opinion of counsel to the Issuer, addressed to the Dealer, satisfactory in form and substance to the Dealer, (b) a copy of the executed Issuing and Paying Agency Agreement as then in effect, (c) a copy of resolutions adopted by the Board of Directors of the Issuer, satisfactory in form and substance to the Dealer and certified by the Secretary or similar officer of the Issuer authorizing execution and delivery by the Issuer of this Agreement, the Issuing and Paying Agency Agreement and the Notes and consummation by the Issuer of the transactions contemplated hereby and thereby, (d) prior to the issuance of any book-entry Notes represented by a master note registered in the name of DTC or its nominee, a copy of the executed Letter of Representations among the Issuer, the Issuing and Paying Agent and DTC

and of the executed master note, (e) prior to the issuance of any Notes in physical form, a copy of such form (unless attached to this Agreement or the Issuing and Paying Agency Agreement) and (f) such other certificates, opinions, letters and documents as the Dealer shall have reasonably requested.

4. Disclosure.

4.1 Offering Materials which may be provided to purchasers and prospective purchasers of the Notes shall be prepared for use in connection with the transactions contemplated by this Agreement. The Offering Materials and their contents (other than the Dealer Information) shall be the sole responsibility of the Issuer. The Issuer authorizes the Dealer to distribute the Offering Materials as determined by the Dealer.

4.2 The Issuer agrees to promptly furnish the Dealer the Company Information as it becomes available.

4.3 (a) The Issuer further agrees to notify the Dealer promptly upon the occurrence of any event relating to or affecting the Issuer that would cause the Company Information then in existence to include an untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements contained therein, in light of the circumstances under which they are made, not misleading.

(b) In the event that the Issuer gives the Dealer notice pursuant to Section 4.3(a) and the Dealer notifies the Issuer that it then has Notes it is holding in inventory, the Issuer agrees promptly to supplement or amend the Offering Materials so that the Offering Materials, as amended or supplemented, shall not contain an untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, and the Issuer shall make such supplement or amendment available to the Dealer.

(c) In the event that (i) the Issuer gives the Dealer notice pursuant to Section 4.3(a), (ii) the Dealer does not notify the Issuer that it is then holding Notes in inventory and (iii) the Issuer chooses not to promptly amend or supplement the Offering Materials in the manner described in clause (b) above, then all solicitations and sales of Notes shall be suspended until such time as the Issuer has so amended or supplemented the Offering Materials, and made such amendment or supplement available to the Dealer.

5. Indemnification and Contribution.

5.1 The Issuer will indemnify and hold harmless the Dealer, each individual, corporation, partnership, trust, association or other entity controlling the Dealer, any affiliate of the Dealer or any such controlling entity and their respective directors, officers, employees, partners, incorporators, shareholders, servants, trustees and agents (hereinafter the "Indemnitees") against any and all liabilities, penalties, suits, causes of action, losses, damages, claims, costs and expenses (including, without limitation, fees and disbursements of counsel) or judgments of whatever kind or nature (each a "Claim"), imposed upon, incurred by or asserted against the Indemnitees arising out of or based upon (i) any allegation that the Offering Materials or the Company Information included (as of any relevant time) or includes an untrue statement of a material fact or omitted (as of any relevant time) or omits to state any material fact necessary to make the statements therein, in light of the circumstances under which they were made, not

misleading or (ii) arising out of or based upon the breach by the Issuer of any agreement, covenant or representation made in or pursuant to this Agreement. This indemnification shall not apply to the extent that the Claim arises out of or is based upon Dealer Information.

5.2 Provisions relating to claims made for indemnification under this Section 5 are set forth on Exhibit A to this Agreement.

5.3 In order to provide for just and equitable contribution in circumstances in which the indemnification provided for in this Section 5 is held to be unavailable or insufficient to hold harmless the Indemnitees, although applicable in accordance with the terms of this Section 5, the Issuer shall contribute to the aggregate costs incurred by the Dealer in connection with any Claim in the proportion of the respective economic interests of the Issuer and the Dealer; provided, however, such contribution by the Issuer shall be in an amount such that the aggregate costs incurred by the Dealer do not exceed the aggregate of the commissions and fees earned by the Dealer hereunder with respect to the issue or issues of Notes to which such Claim relates. The respective economic interests shall be calculated by reference to the aggregate proceeds to the Issuer of the Notes issued hereunder and the aggregate commissions and fees earned by the Dealer hereunder.

6. Definitions.

6.1 "Claim" shall have the meaning set forth in Section 5.1.

6.2 "Company Information" at any given time shall mean the Offering Materials together with, to the extent applicable, (i) the Issuer's most recent report on Form 10-K filed with the SEC and each report on Form 10-Q or 8-K filed by the Issuer with the SEC since the most recent Form 10-K, (ii) the Issuer's most recent annual audited financial statements and each interim financial statement or report prepared subsequent thereto, if not included in item (i) above, (iii) the Issuer's and its affiliates' other publicly available recent reports, including, but not limited to, any publicly available filings or reports provided to their respective shareholders, (iv) any other information or disclosure prepared pursuant to Section 4.3 hereof and (v) any information prepared or approved by the Issuer for dissemination to investors or potential investors in the Notes.

6.3 "Dealer Information" shall mean material concerning the Dealer provided by the Dealer in writing expressly for inclusion in the Offering Materials.

6.4 "Indemnitee" shall have the meaning set forth in Section 5.1.

6.5 "Issuing and Paying Agency Agreement" shall mean the issuing and paying agency agreement described on the cover page of this Agreement, as such agreement may be amended or supplemented from time to time.

6.6 "Issuing and Paying Agent" shall mean the party designated as such on the cover page of this Agreement, as issuing and paying agent under the Issuing and Paying Agency Agreement, or any successor thereto in accordance with the Issuing and Paying Agency Agreement.

6.7 "Offering Materials" shall mean offering materials prepared in accordance with Section 4 (including materials referred to therein or incorporated by reference therein, if any) which may be provided to purchasers and prospective purchasers of the Notes, and shall include

amendments and supplements thereto which may be prepared from time to time in accordance with this Agreement (other than any amendment or supplement that has been completely superseded by a later amendment or supplement).

6.8 "SEC" shall mean the U.S. Securities and Exchange Commission.

6.9 "Securities Act" shall mean the U.S. Securities Act of 1933, as amended.

7. General.

7.1 Unless otherwise expressly provided herein, all notices under this Agreement to parties hereto shall be in writing and shall be effective when received at the address of the respective party set forth in the Addendum to this Agreement.

7.2 This Agreement shall be governed by and construed in accordance with the laws of the State of New York, without regard to its conflict of laws provisions.

7.3 The Issuer agrees that any suit, action or proceeding brought by the Issuer against the Dealer in connection with or arising out of this Agreement or the Notes or the offer and sale of the Notes shall be brought solely in the United States federal courts located in the Borough of Manhattan or the courts of the State of New York located in the Borough of Manhattan. EACH OF THE DEALER AND THE ISSUER WAIVES ITS RIGHT TO TRIAL BY JURY IN ANY SUIT, ACTION OR PROCEEDING WITH RESPECT TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

7.4 This Agreement may be terminated, at any time, by the Issuer, upon one business day's prior notice to such effect to the Dealer, or by the Dealer upon one business day's prior notice to such effect to the Issuer. Any such termination, however, shall not affect the obligations of the Issuer under Sections 3.8, 5 and 7.3 hereof or the respective representations, warranties, agreements, covenants, rights or responsibilities of the parties made or arising prior to the termination of this Agreement.

7.5 This Agreement is not assignable by either party hereto without the written consent of the other party; provided, however, that the Dealer may assign its rights and obligations under this Agreement to any affiliate of the Dealer.

7.6 This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

7.7 This Agreement is for the exclusive benefit of the parties hereto, and their respective permitted successors and assigns hereunder, and shall not be deemed to give any legal or equitable right, remedy or claim to any other person whatsoever.

7.8 The Issuer acknowledges and agrees that the Dealer is acting solely in the capacity of an arm's length contractual counterparty to the Issuer with respect to the offering of the Notes contemplated hereby (including in connection with determining the price and terms of the offering) and not as a financial advisor or a fiduciary to, or an agent of (except to the extent explicitly set forth herein), the Issuer or any other person. The Dealer has not assumed an advisory or fiduciary responsibility in favor of the Issuer with respect to the offering contemplated hereby or the process leading thereto (irrespective of whether the Dealer has

advised or is currently advising the Issuer on other matters) or any other obligation to the Issuer except the obligations expressly set forth in this Agreement. Additionally, the Dealer is not advising the Issuer or any other person as to any legal, tax, investment, accounting or regulatory matters in any jurisdiction. The Issuer shall consult with its own advisors concerning such matters and shall be responsible for making its own independent investigation and appraisal of the transactions contemplated hereby, and the Dealer shall have no responsibility or liability to the Issuer with respect thereto. Any review by the Dealer of the Issuer, the transactions contemplated hereby or other matters relating to such transactions will be performed solely for the benefit of the Dealer and shall not be on behalf of the Issuer. The Issuer hereby waives and releases, to the fullest extent permitted by law, any claims that it may have against the Dealer with respect to any breach or alleged breach of fiduciary duty.

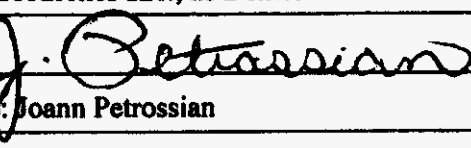
IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

Florida Power Corporation d/b/a Progress Energy Florida, Inc., as Issuer

By:

Name: Thomas F. Moses, Assistant Treasurer

RBS Securities Inc., as Dealer

By: 

Name: Joann Petrossian

Title: Managing Director

Addendum[1]

The following additional clauses shall apply to the Agreement and be deemed a part thereof.

1. The other dealers referred to in clause (b) of Section 1.2 of the Agreement are: J.P.Morgan Securities Inc., SunTrust Robinson Humphrey, Inc., and Merrill Lynch, Pierce, Fenner & Smith Inc.

2. The following Section 3.9 is hereby added to the Agreement:

   3.9 Without limiting any obligation of the Issuer pursuant to this Agreement to provide the Dealer with credit and financial information, the Issuer hereby acknowledges and agrees that the Dealer may share the Company Information and any other information or matters relating to the Issuer or the transactions contemplated hereby with affiliates of the Dealer, including, but not limited to, Bank of America, N.A., and that such affiliates may likewise share information relating to the Issuer or such transactions with the Dealer.

3. The addresses of the respective parties for purposes of notices under Section 7.1 are as follows:

   For the Issuer:

   Address: 410 S. Wilmington Street, Raleigh, NC 27601
   Attention: Treasury – Financial Ops
   Telephone number: 919-546-7517
   Fax number: 919-235-3190

   For the Dealer:

Address:	600 Washington Boulevard
	Stamford, CT 06901
Attention:	Commercial Paper Origination
Telephone number:	203-897-4691
Fax number:	203-873-4307

Exhibit A

Further Provisions Relating to Indemnification

(a) The Issuer agrees to reimburse each Indemnitee for all expenses (including reasonable fees and disbursements of internal and external counsel) as they are incurred by it in connection with investigating or defending any loss, claim, damage, liability or action in respect of which indemnification may be sought under Section 5 of the Agreement (whether or not it is a party to any such proceedings).

(b) Promptly after receipt by an Indemnitee of notice of the existence of a Claim, such Indemnitee will, if a claim in respect thereof is to be made against the Issuer, notify the Issuer in writing of the existence thereof; provided that (i) the omission so to notify the Issuer will not relieve the Issuer from any liability which it may have hereunder unless and except to the extent it did not otherwise learn of such Claim and such failure results in the forfeiture by the Issuer of substantial rights and defenses, and (ii) the omission so to notify the Issuer will not relieve it from liability which it may have to an Indemnitee otherwise than on account of this indemnity agreement. In case any such Claim is made against any Indemnitee and it notifies the Issuer of the existence thereof, the Issuer will be entitled to participate therein, and to the extent that it may elect by written notice delivered to the Indemnitee, to assume the defense thereof, with counsel reasonably satisfactory to such Indemnitee; provided that if the defendants in any such Claim include both the Indemnitee and the Issuer, and the Indemnitee shall have concluded that there may be legal defenses available to it which are different from or additional to those available to the Issuer, the Issuer shall not have the right to direct the defense of such Claim on behalf of such Indemnitee, and the Indemnitee shall have the right to select separate counsel to assert such legal defenses on behalf of such Indemnitee. Upon receipt of notice from the Issuer to such Indemnitee of the Issuer's election so to assume the defense of such Claim and approval by the Indemnitee of counsel, the Issuer will not be liable to such Indemnitee for expenses incurred thereafter by the Indemnitee in connection with the defense thereof (other than reasonable costs of investigation) unless (i) the Indemnitee shall have employed separate counsel in connection with the assertion of legal defenses in accordance with the proviso to the next preceding sentence (it being understood, however, that the Issuer shall not be liable for the expenses of more than one separate counsel (in addition to any local counsel in the jurisdiction in which any Claim is brought), approved by the Dealer, representing the Indemnitee who is party to such Claim), (ii) the Issuer shall not have employed counsel reasonably satisfactory to the Indemnitee to represent the Indemnitee within a reasonable time after notice of existence of the Claim or (iii) the Issuer has authorized in writing the employment of counsel for the Indemnitee. The indemnity, reimbursement and contribution obligations of the Issuer hereunder shall be in addition to any other liability the Issuer may otherwise have to an Indemnitee and shall be binding upon and inure to the benefit of any successors, assigns, heirs and personal representatives of the Issuer and any Indemnitee. The Issuer agrees that without the Dealer's prior written consent, it will not settle, compromise or consent to the entry of any judgment in any Claim in respect of which indemnification may be sought under the indemnification provision of the Agreement (whether or not the Dealer or any other Indemnitee is an actual or potential party to such Claim), unless such settlement, compromise or consent (i) includes an unconditional release of each Indemnitee from all liability arising out of such Claim, and (ii) does not include a statement as to or an admission of fault, culpability or failure to act, by or on behalf of any Indemnitee.

Exhibit B

Statement of Terms for Interest – Bearing Commercial Paper Notes of Florida Power Corporation d/b/a Progress Energy Florida, Inc.

THE PROVISIONS SET FORTH BELOW ARE QUALIFIED TO THE EXTENT APPLICABLE BY THE TRANSACTION SPECIFIC PRICING SUPPLEMENT (THE "SUPPLEMENT") (IF ANY) SENT TO EACH PURCHASER AT THE TIME OF THE TRANSACTION.

1. General. (a) The obligations of the Issuer to which these terms apply (each a "Note") are represented by one or more Master Notes (each, a "Master Note") issued in the name of (or of a nominee for) The Depository Trust Company ("DTC"), which Master Note includes the terms and provisions for the Issuer's Interest-Bearing Commercial Paper Notes that are set forth in this Statement of Terms, since this Statement of Terms constitutes an integral part of the Underlying Records as defined and referred to in the Master Note.

(b) "Business Day" means any day other than a Saturday or Sunday that is neither a legal holiday nor a day on which banking institutions are authorized or required by law, executive order or regulation to be closed in New York City and, with respect to LIBOR Notes (as defined below) is also a London Business Day. "London Business Day" means, a day, other than a Saturday or Sunday, on which dealings in deposits in U.S. dollars are transacted in the London interbank market.

2. Interest. (a) Each Note will bear interest at a fixed rate (a "Fixed Rate Note") or at a floating rate (a "Floating Rate Note").

(b) The Supplement sent to each holder of such Note will describe the following terms: (i) whether such Note is a Fixed Rate Note or a Floating Rate Note and whether such Note is an Original Issue Discount Note (as defined below); (ii) the date on which such Note will be issued (the "Issue Date"); (iii) the Stated Maturity Date (as defined below); (iv) if such Note is a Fixed Rate Note, the rate per annum at which such Note will bear interest, if any, and the Interest Payment Dates; (v) if such Note is a Floating Rate Note, the Base Rate, the Index Maturity, the Interest Reset Dates, the Interest Payment Dates and the Spread and/or Spread Multiplier, if any (all as defined below), and any other terms relating to the particular method of calculating the interest rate for such Note; and (vi) any other terms applicable specifically to such Note. "Original Issue Discount Note" means a Note which has a stated redemption price at the Stated Maturity Date that exceeds its Issue Price by more than a specified *de minimis* amount and which the Supplement indicates will be an "Original Issue Discount Note".

(c) Each Fixed Rate Note will bear interest from its Issue Date at the rate per annum specified in the Supplement until the principal amount thereof is paid or made available for payment. Interest on each Fixed Rate Note will be payable on the dates specified in the Supplement (each an "Interest Payment Date" for a Fixed Rate Note) and on the Maturity Date (as defined below). Interest on Fixed Rate Notes will be computed on the basis of a 360-day year of twelve 30-day months.

If any Interest Payment Date or the Maturity Date of a Fixed Rate Note falls on a day that is not a Business Day, the required payment of principal, premium, if any, and/or interest will be payable on the next succeeding Business Day, and no additional interest will accrue in respect of the payment made on that next succeeding Business Day.

(d) The interest rate on each Floating Rate Note for each Interest Reset Period (as defined below) will be determined by reference to an interest rate basis (a "Base Rate") plus or minus a number of basis points (one basis point equals one-hundredth of a percentage point) (the "Spread"), if any, and/or multiplied by a certain percentage (the "Spread Multiplier"), if any, until the principal thereof is paid or made available for payment. The Supplement will designate which of the following Base Rates is applicable to the related Floating Rate Note: (a) the CD Rate (a "CD Rate Note"), (b) the Commercial Paper Rate (a "Commercial Paper Rate Note"), (c) the Federal Funds Rate (a "Federal Funds Rate Note"), (d) LIBOR (a "LIBOR Note"), (e) the Prime Rate (a "Prime Rate Note"), (f) the Treasury Rate (a "Treasury Rate Note") or (g) such other Base Rate as may be specified in such Supplement.

The rate of interest on each Floating Rate Note will be reset daily, weekly, monthly, quarterly or semi-annually (the "Interest Reset Period"). The date or dates on which interest will be reset (each an "Interest Reset Date") will be, unless otherwise specified in the Supplement, in the case of Floating Rate Notes which reset daily, each Business Day, in the case of Floating Rate Notes (other than Treasury Rate Notes) that reset weekly, the Wednesday of each week; in the case of Treasury Rate Notes that reset weekly, the Tuesday of each week; in the case of Floating Rate Notes that reset monthly, the third Wednesday of each month; in the case of Floating Rate Notes that reset quarterly, the third Wednesday of March, June, September and December; and in the case of Floating Rate Notes that reset semiannually, the third Wednesday of the two months specified in the Supplement. If any Interest Reset Date for any Floating Rate Note is not a Business Day, such Interest Reset Date will be postponed to the next day that is a Business Day, except that in the case of a LIBOR Note, if such Business Day is in the next succeeding calendar month, such Interest Reset Date shall be the immediately preceding Business Day. Interest on each Floating Rate Note will be payable monthly, quarterly or semiannually (the "Interest Payment Period") and on the Maturity Date. Unless otherwise specified in the Supplement, and except as provided below, the date or dates on which interest will be payable (each an "Interest Payment Date" for a Floating Rate Note) will be, in the case of Floating Rate Notes with a monthly Interest Payment Period, on the third Wednesday of each month; in the case of Floating Rate Notes with a quarterly Interest Payment Period, on the third Wednesday of March, June, September and December; and in the case of Floating Rate Notes with a semiannual Interest Payment Period, on the third Wednesday of the two months specified in the Supplement. In addition, the Maturity Date will also be an Interest Payment Date.

If any Interest Payment Date for any Floating Rate Note (other than an Interest Payment Date occurring on the Maturity Date) would otherwise be a day that is not a Business Day, such Interest Payment Date shall be postponed to the next day that is a Business Day, except that in the case of a LIBOR Note, if such Business Day is in the next succeeding calendar month, such Interest Payment Date shall be the immediately preceding Business Day. If the Maturity Date of a Floating Rate Note falls on a day that is not a Business Day, the payment of principal and interest will be made on the next succeeding Business Day, and no interest on such payment shall accrue for the period from and after such maturity.

Interest payments on each Interest Payment Date for Floating Rate Notes will include accrued interest from and including the Issue Date or from and including the last date in respect of which interest has been paid, as the case may be, to, but excluding, such Interest Payment Date. On the Maturity Date, the interest payable on a Floating Rate Note will include interest accrued to, but excluding, the Maturity Date. Accrued interest will be calculated by multiplying the principal amount of a Floating

Rate Note by an accrued interest factor. This accrued interest factor will be computed by adding the interest factors calculated for each day in the period for which accrued interest is being calculated. The interest factor (expressed as a decimal) for each such day will be computed by dividing the interest rate applicable to such day by 360, in the cases where the Base Rate is the CD Rate, Commercial Paper Rate, Federal Funds Rate, LIBOR or Prime Rate, or by the actual number of days in the year, in the case where the Base Rate is the Treasury Rate. The interest rate in effect on each day will be (i) if such day is an Interest Reset Date, the interest rate with respect to the Interest Determination Date (as defined below) pertaining to such Interest Reset Date, or (ii) if such day is not an Interest Reset Date, the interest rate with respect to the Interest Determination Date pertaining to the next preceding Interest Reset Date, subject in either case to any adjustment by a Spread and/or a Spread Multiplier.

The "Interest Determination Date" where the Base Rate is the CD Rate or the Commercial Paper Rate will be the second Business Day next preceding an Interest Reset Date. The Interest Determination Date where the Base Rate is the Federal Funds Rate or the Prime Rate will be the Business Day next preceding an Interest Reset Date. The Interest Determination Date where the Base Rate is LIBOR will be the second London Business Day next preceding an Interest Reset Date. The Interest Determination Date where the Base Rate is the Treasury Rate will be the day of the week in which such Interest Reset Date falls when Treasury Bills are normally auctioned. Treasury Bills are normally sold at auction on Monday of each week, unless that day is a legal holiday, in which case the auction is held on the following Tuesday or the preceding Friday. If an auction is so held on the preceding Friday, such Friday will be the Interest Determination Date pertaining to the Interest Reset Date occurring in the next succeeding week.

The "Index Maturity" is the period to maturity of the instrument or obligation from which the applicable Base Rate is calculated.

The "Calculation Date," where applicable, shall be the earlier of (i) the tenth calendar day following the applicable Interest Determination Date or (ii) the Business Day preceding the applicable Interest Payment Date or Maturity Date.

All times referred to herein reflect New York City time, unless otherwise specified.

The Issuer shall specify in writing to the Issuing and Paying Agent which party will be the calculation agent (the "Calculation Agent") with respect to the Floating Rate Notes. The Calculation Agent will provide the interest rate then in effect and, if determined, the interest rate which will become effective on the next Interest Reset Date with respect to such Floating Rate Note to the Issuing and Paying Agent as soon as the interest rate with respect to such Floating Rate Note has been determined and as soon as practicable after any change in such interest rate.

All percentages resulting from any calculation on Floating Rate Notes will be rounded to the nearest one hundred-thousandth of a percentage point, with five-one millionths of a percentage point rounded upwards. For example, 9.876545% (or .09876545) would be rounded to 9.87655% (or .0987655). All dollar amounts used in or resulting from any calculation on Floating Rate Notes will be rounded, in the case of U.S. dollars, to the nearest cent or, in the case of a foreign currency, to the nearest unit (with one-half cent or unit being rounded upwards).

CD Rate Notes

"CD Rate" means the rate on any Interest Determination Date for negotiable certificates of deposit having the Index Maturity as published by the Board of Governors of the Federal Reserve System (the "FRB") in "Statistical Release H.15(519), Selected Interest Rates" or any successor publication of the FRB ("H.15(519)") under the heading "CDs (Secondary Market)".

If the above rate is not published in H.15(519) by 3:00 p.m. on the Calculation Date, the CD Rate will be the rate on such Interest Determination Date set forth in the daily update of H.15(519), available through the world wide website of the FRB at http://www.federalreserve.gov/releases/h15/Update, or any successor site or publication or other recognized electronic source used for the purpose of displaying the applicable rate ("H.15 Daily Update") under the caption "CDs (Secondary Market)".

If such rate is not published in either H.15(519) or H.15 Daily Update by 3:00 p.m. on the Calculation Date, the Calculation Agent will determine the CD Rate to be the arithmetic mean of the secondary market offered rates as of 10:00 a.m. on such Interest Determination Date of three leading nonbank dealers[2] in negotiable U.S. dollar certificates of deposit in New York City selected by the Calculation Agent for negotiable U.S. dollar certificates of deposit of major United States money center banks of the highest credit standing in the market for negotiable certificates of deposit with a remaining maturity closest to the Index Maturity in the denomination of $5,000,000.

If the dealers selected by the Calculation Agent are not quoting as set forth above, the CD Rate will remain the CD Rate then in effect on such Interest Determination Date.

Commercial Paper Rate Notes

"Commercial Paper Rate" means the Money Market Yield (calculated as described below) of the rate on any Interest Determination Date for commercial paper having the Index Maturity, as published in H.15(519) under the heading "Commercial Paper-Nonfinancial".

If the above rate is not published in H.15(519) by 3:00 p.m. on the Calculation Date, then the Commercial Paper Rate will be the Money Market Yield of the rate on such Interest Determination Date for commercial paper of the Index Maturity as published in H.15 Daily Update under the heading "Commercial Paper-Nonfinancial".

If by 3:00 p.m. on such Calculation Date such rate is not published in either H.15(519) or H.15 Daily Update, then the Calculation Agent will determine the Commercial Paper Rate to be the Money Market Yield of the arithmetic mean of the offered rates as of 11:00 a.m. on such Interest Determination Date of three leading dealers of U.S. dollar commercial paper in New York City selected by the Calculation Agent for commercial paper of the Index Maturity placed for an industrial issuer whose bond rating is "AA," or the equivalent, from a nationally recognized statistical rating organization.

If the dealers selected by the Calculation Agent are not quoting as mentioned above, the Commercial Paper Rate with respect to such Interest Determination Date will remain the Commercial Paper Rate then in effect on such Interest Determination Date.

"Money Market Yield" will be a yield calculated in accordance with the following formula:

$$\text{Money Market Yield} = \frac{D \times 360}{\text{——————}} \times 100$$

[2] Such nonbank dealers referred to in this Statement of Terms may include affiliates of the Dealer.

360 - (D x M)

where "D" refers to the applicable per annum rate for commercial paper quoted on a bank discount basis and expressed as a decimal and "M" refers to the actual number of days in the interest period for which interest is being calculated.

Federal Funds Rate Notes

"Federal Funds Rate" means the rate on any Interest Determination Date for federal funds as published in H.15(519) under the heading "Federal Funds (Effective)" and displayed on Reuters Page (as defined below) FEDFUNDS1 (or any other page as may replace the specified page on that service) ("Reuters Page FEDFUNDS1") under the heading EFFECT.

If the above rate does not appear on Reuters Page Fed Funds 1 or is not so published by 3:00 p.m. on the Calculation Date, the Federal Funds Rate will be the rate on such Interest Determination Date as published in H.15 Daily Update under the heading "Federal Funds/(Effective)".

If such rate is not published as described above by 3:00 p.m. on the Calculation Date, the Calculation Agent will determine the Federal Funds Rate to be the arithmetic mean of the rates for the last transaction in overnight U.S. dollar federal funds arranged by each of three leading brokers of Federal Funds transactions in New York City selected by the Calculation Agent prior to 9:00 a.m. on such Interest Determination Date.

If the brokers selected by the Calculation Agent are not quoting as mentioned above, the Federal Funds Rate will remain the Federal Funds Rate then in effect on such Interest Determination Date.

"Reuters Page" means the display on the Reuters 3000 Xtra Service, or any successor service, on the page or pages specified in this Statement of Terms or the Supplement, or any replacement page on that service.

LIBOR Notes

The London Interbank offered rate ("LIBOR") means, with respect to any Interest Determination Date, the rate for deposits in U.S. dollars having the Index Maturity that appears on the Designated LIBOR Page as of 11:00 a.m., London time, on such Interest Determination Date.

If no rate appears, LIBOR will be determined on the basis of the rates at approximately 11:00 a.m., London time, on such Interest Determination Date at which deposits in U.S. dollars are offered to prime banks in the London interbank market by four major banks in such market selected by the Calculation Agent for a term equal to the Index Maturity and in principal amount equal to an amount that in the Calculation Agent's judgment is representative for a single transaction in U.S. dollars in such market at such time (a "Representative Amount"). The Calculation Agent will request the principal London office of each of such banks to provide a quotation of its rate. If at least two such quotations are provided, LIBOR will be the arithmetic mean of such quotations. If fewer than two quotations are provided, LIBOR for such interest period will be the arithmetic mean of the rates quoted at approximately 11:00 a.m., in New York City, on such Interest Determination Date by three major banks in New York City, selected by the Calculation Agent, for loans in U.S. dollars to leading European banks, for a term equal to the Index Maturity and in a Representative Amount; provided,

however, that if fewer than three banks so selected by the Calculation Agent are providing such quotations, the then existing LIBOR rate will remain in effect for such Interest Payment Period.

"Designated LIBOR Page" means the display on the Reuters 3000 Xtra Service (or any successor service) on the "LIBOR01" page (or any other page as may replace such page on such service) for the purpose of displaying the London interbank rates of major banks.

Prime Rate Notes

"Prime Rate" means the rate on any Interest Determination Date as published in H.15(519) under the heading "Bank Prime Loan".

If the above rate is not published in H.15(519) prior to 3:00 p.m. on the Calculation Date, then the Prime Rate will be the rate on such Interest Determination Date as published in H.15 Daily Update opposite the caption "Bank Prime Loan".

If the rate is not published prior to 3:00 p.m. on the Calculation Date in either H.15(519) or H.15 Daily Update, then the Calculation Agent will determine the Prime Rate to be the arithmetic mean of the rates of interest publicly announced by each bank that appears on the Reuters Screen US PRIME1 Page (as defined below) as such bank's prime rate or base lending rate as of 11:00 a.m., on that Interest Determination Date.

If fewer than four such rates referred to above are so published by 3:00 p.m. on the Calculation Date, the Calculation Agent will determine the Prime Rate to be the arithmetic mean of the prime rates or base lending rates quoted on the basis of the actual number of days in the year divided by 360 as of the close of business on such Interest Determination Date by three major banks in New York City selected by the Calculation Agent.

If the banks selected are not quoting as mentioned above, the Prime Rate will remain the Prime Rate in effect on such Interest Determination Date.

"Reuters Screen US PRIME1 Page" means the display designated as page "US PRIME1" on the Reuters Monitor Money Rates Service (or such other page as may replace the US PRIME1 page on that service for the purpose of displaying prime rates or base lending rates of major United States banks).

Treasury Rate Notes

"Treasury Rate" means:

(1) the rate from the auction held on the Interest Determination Date (the "Auction") of direct obligations of the United States ("Treasury Bills") having the Index Maturity specified in the Supplement under the caption "INVEST RATE" on the display on the Reuters Page designated as USAUCTION10 (or any other page as may replace that page on that service) or the Reuters Page designated as USAUCTION11 (or any other page as may replace that page on that service), or

(2) if the rate referred to in clause (1) is not so published by 3:00 p.m. on the related Calculation Date, the Bond Equivalent Yield (as defined below) of the rate for the applicable Treasury Bills as published in H.15 Daily Update, under the caption "U.S. Government Securities/Treasury Bills/Auction High", or

(3) if the rate referred to in clause (2) is not so published by 3:00 p.m. on the related Calculation Date, the Bond Equivalent Yield of the auction rate of the applicable Treasury Bills as announced by the United States Department of the Treasury, or

(4) if the rate referred to in clause (3) is not so announced by the United States Department of the Treasury, or if the Auction is not held, the Bond Equivalent Yield of the rate on the particular Interest Determination Date of the applicable Treasury Bills as published in H.15(519) under the caption "U.S. Government Securities/Treasury Bills/Secondary Market", or

(5) if the rate referred to in clause (4) not so published by 3:00 p.m. on the related Calculation Date, the rate on the particular Interest Determination Date of the applicable Treasury Bills as published in H.15 Daily Update, under the caption "U.S. Government Securities/Treasury Bills/Secondary Market", or

(6) if the rate referred to in clause (5) is not so published by 3:00 p.m. on the related Calculation Date, the rate on the particular Interest Determination Date calculated by the Calculation Agent as the Bond Equivalent Yield of the arithmetic mean of the secondary market bid rates, as of approximately 3:30 p.m. on that Interest Determination Date, of three primary United States government securities dealers selected by the Calculation Agent, for the issue of Treasury Bills with a remaining maturity closest to the Index Maturity specified in the Supplement, or

(7) if the dealers so selected by the Calculation Agent are not quoting as mentioned in clause (6), the Treasury Rate in effect on the particular Interest Determination Date.

"Bond Equivalent Yield" means a yield (expressed as a percentage) calculated in accordance with the following formula:

$$\text{Bond Equivalent Yield} = \frac{D \times N}{360 - (D \times M)} \times 100$$

where "D" refers to the applicable per annum rate for Treasury Bills quoted on a bank discount basis and expressed as a decimal, "N" refers to 270, as the case may be, and "M" refers to the actual number of days in the applicable Interest Reset Period.

3. Final Maturity. The Stated Maturity Date for any Note will be the date so specified in the Supplement, which shall be no later than 270 days from the date of issuance (exclusive of days of grace). On its Stated Maturity Date, or any date prior to the Stated Maturity Date on which the particular Note becomes due and payable by the declaration of acceleration, each such date being referred to as a Maturity Date, the principal amount of each Note, together with accrued and unpaid interest thereon, will be immediately due and payable.

4. Events of Default. The occurrence of any of the following shall constitute an "Event of Default" with respect to a Note: (i) default in any payment of principal of or interest on such Note (including on a redemption thereof); (ii) the Issuer makes any compromise arrangement with its creditors generally including the entering into any form of moratorium with its creditors generally; (iii) a court having jurisdiction shall enter a decree or order for relief in respect of the Issuer in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or

there shall be appointed a receiver, administrator, liquidator, custodian, trustee or sequestrator (or similar officer) with respect to the whole or substantially the whole of the assets of the Issuer and any such decree, order or appointment is not removed, discharged or withdrawn within 60 days thereafter; or (iv) the Issuer shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consent to the entry of an order for relief in an involuntary case under any such law, or consent to the appointment of or taking possession by a receiver, administrator, liquidator, assignee, custodian, trustee or sequestrator (or similar official), with respect to the whole or substantially the whole of the assets of the Issuer or make any general assignment for the benefit of creditors. Upon the occurrence of an Event of Default, the principal of each obligation evidenced by such Note (together with interest accrued and unpaid thereon) shall become, without any notice or demand, immediately due and payable.[3]

5. Obligation Absolute. No provision of the Issuing and Paying Agency Agreement under which the Notes are issued shall alter or impair the obligation of the Issuer, which is absolute and unconditional, to pay the principal of and interest on each Note at the times, place and rate, and in the coin or currency, herein prescribed.

6. Supplement. Any term contained in the Supplement shall supercede any conflicting term contained herein.

[3] Unlike single payment notes, where a default arises only at the stated maturity, interest-bearing notes with multiple payment dates should contain a default provision permitting acceleration of the maturity if the Issuer defaults on an interest payment.