Progress Energy

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March 30, 2007

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

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RCA ____
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SGA ____
SEC ____
OTH ____

Re: *Docket No. 050844-EI; Consummation Report for 2006*

Dear Ms. Cole:

Pursuant to Order No. PSC-05-1222-FOF-EI, issued December 15, 2005 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 2006.

Please acknowledge receipt and filing of the above by stamping a copy of this letter and returning to me. If you should have any questions, please feel free to contact me at (727) 820-5184.

Thank you for your assistance in this matter.

Sincerely,

R. Alexander Glenn LMS

R. Alexander Glenn

RAG/lms
Enclosure

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DOCKET NO. 050844-EI

FLORIDA PUBLIC SERVICE COMMISSION

TALLAHASSEE, FLORIDA

CONSUMMATION REPORT

TO

APPLICATION OF

PROGRESS ENERGY FLORIDA, INC.
(FORMERLY, FLORIDA POWER CORPORATION)

FOR AUTHORITY TO ISSUE AND SELL

SECURITIES DURING 2006

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
Deputy General Counsel
Progress Energy Service Company, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042

Dated: March 30, 2007

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	APPLICATION OF PROGRESS ENERGY FLORIDA, INC. FOR AUTHORITY TO ISSUE AND SELL SECURITIES DURING 2006 PURSUANT TO FLORIDA STATUTES SECTION 366.04 AND CHAPTER 25-8, FLORIDA ADMINISTRATIVE CODE	)	DOCKET NO.050844-EI

The Applicant, Progress Energy Florida, Inc., formerly Florida Power Corporation, (the "Company"), pursuant to Commission Order No. PSC-03-1439-FOF-EI issued December 22, 2003 (the "Order"), and Rule 25-8.009, Florida Administrative Code, hereby files its Consummation Report for 2006 as directed by the terms of the Order and states as follows.

The Company did not issue any commercial paper, medium-term notes or other debt or equity securities during calendar year 2006, except for (i) a note that was delivered to evidence loans to the Company from the Utility Money Pool established pursuant to a Utility Money Pool Agreement, dated as of July 1, 2000 by and among Progress Energy Inc., a North Carolina corporation and a registered holding company under the Public Utility Holding Company Act of 1935, as amended, and its utility subsidiaries, including the Company.

The Company regularly 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 22, 1988 with Merrill Lynch Money Markets Inc., as amended by a Letter Agreement dated November 18, 1997 (the "Merrill CP Agreement"), a Letter Agreement dated

November 20, 1992 with Banc One Capital Markets, Inc., (successor to First Chicago Capital Markets, Inc.), as amended by a Letter Agreement dated December 4, 1997 (the "Banc One CP Agreement"), and a Letter Agreement dated September 29, 2004 with SunTrust Capital Markets, Inc. (the "SunTrust 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 2006 commercial paper activity can be summarized as follows:

2006 Commercial Paper Activity
($ in thousands)

Commercial paper issued:	$0
Commercial paper matured:	$102,000,000
Average outstanding:	$32,126,027
Weighted average yield:	0%
Weighted average term:	0 days

As back-up for its commercial paper program, the Company has executed (i) a Five-Year Credit Agreement with Bank of America, N.A., as Administrative Agent for the lenders named therein, dated as of March 28, 2005, and amended as of May 3, 2006, providing for long-term loans to the Company in the aggregate principal amount not exceeding $450,000,000. No loans have as yet been made to the Company pursuant to the Credit Agreement.

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 approximately $139,436,760 from the Utility Money Pool during 2006. As of December 31, 2006, the Company had outstanding borrowings of approximately $46,794,314 from the Utility Money Pool. The average interest rate on outstanding Money Pool balances was 5.167%.

A statement showing capitalization, pretax interest coverage, and debt interest and preferred stock dividend requirements at December 31, 2006 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	Five-Year Credit Agreement, dated as of March 28, 2005, between the Company, the Lenders named therein, and Bank of America, N.A., as administrative agent for the Lenders. (Included as Exhibit (1)-a to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).
(1)-b	Commercial Paper Issuer Memorandum dated November 17, 1998 of Merrill Lynch Money Markets Inc. (Included as Exhibit (a)-3 to the Company's Consummation Report filed with the Commission on March 31, 1999 in Docket No. 971311-EI, and incorporated herein by reference).
(1)-c	Commercial Paper Offering Memorandum dated August 11, 1999 of Banc One Capital Markets, Inc. (successor to First Chicago Capital Markets, Inc.). (Included as Exhibit (a)-5 to the Company's Consummation Report filed with the Commission on March 23, 2000 in Docket No. 981268-EI, and incorporated herein by reference.)

Exhibit No.	Description of Exhibit
(1)-d	Commercial Paper Information Memorandum dated September 29, 2004 of SunTrust Capital Markets, Inc. (Included as Exhibit (1)-d to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).
(1)-e	The Company has entered into a Forty-fifth Supplemental Indenture, dated as of May 1, 2005, to its Indenture, dated January 1, 1944, as supplemented, (the "Mortgage"), with JPMorgan Chase Bank, N.A., as Successor Trustee, in connection with the issuance of the Company's First Mortgage Bonds, 4.50% Series due 2010. (Included as Exhibit (1)-e to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).
(1)-f	Amendment dated as of May 3, 2006 to the Five-Year Credit Agreement, dated as of March 28, 2005, between the Company, the Lenders named therein, and Bank of America, N.A., as administrative agent for the Lenders.
(1)-g	Utility Money Pool Agreement dated July 1, 2000 between Progress Energy, Inc., Carolina Power & Light Company, a North Carolina Corporation, North Carolina Natural Gas Corporation, a Delaware Corporation, Florida Power Corporation, and Progress Energy Service Company, LLC (solely as Administrator). (Included as Exhibit (a)-6 to the Company's Consummation Report filed with the Commission on April 2, 2001 in Docket No. 991525-EI, and incorporated herein by reference.)
(2)-a	Opinion of Hunton & Williams, Counsel to the Company, dated March 28, 2005, to Bank of America, N.A., as administrative agent for the Lenders, regarding the legality of the Five-Year Credit Agreement. (Included as Exhibit (2)-a to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).
(2)-b	Opinion of R. Alexander Glenn, Associate General Counsel of Progress Energy Service Company, LLC, on behalf of the Company, dated March 28, 2005, to Bank of America, N.A., as administrative agent for the Lenders, regarding the legality of the Five-Year Credit Agreement. (Included as Exhibit (2)-b to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).

Exhibit No.	**Description of Exhibit**
(3)-a	Amendment No. 1 to Registration Statement on Form S-3 (No. 333-103974) of the Company as filed with the Securities and Exchange Commission on April 2, 2003. (Filed as Exhibit (3)-c to the Company's Consummation Report, as filed with the Commission on March 30, 2004, in Docket No. 021029-EI, and incorporated herein by reference.)
(3)-b	Amendment No. 1 to Registration Statement on Form S-3 (No. 333-126967) of the Company as filed with the Securities and Exchange Commission on December 22, 2005. (Included as Exhibit (3)-b to the Company's Consummation Report filed with the Commission on March 31, 2006 in Docket No. 041267-EI, and incorporated herein by reference).
(3)-c	Annual Report on Form 10-K for the fiscal year ended December 31, 2006, filed by the Company with the Commission under the Securities Exchange Act of 1934.
(4)-a	Commercial Paper Dealer Agreement dated December 22, 1998 between the Company and Merrill Lynch Money Markets Inc. (Included as Exhibit (d)-1 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)-b	Letter Agreement dated November 18, 1997 from the Company to Merrill Lynch Money Markets, Inc. regarding the increase in the maximum amount of Commercial Paper outstanding from $400 to $500 million. (Included as Exhibit (d)-2 to the Company's Consummation Report filed with the Commission on September 22, 1997 in Docket No. 961216-EI, and incorporated herein by reference.)
(4)-c	Letter Agreement dated November 20, 1992 between the Company and 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 dated December 4, 1997 from the Company to Banc One Capital Markets, Inc. (successor to First Chicago Capital Markets, Inc.) regarding increase in maximum amount of Commercial Paper outstanding from $400 to $500 million. (Included as Exhibit (d)-2 to the Company's Consummation Report filed with the Commission on September 22, 1997 in Docket No. 961216-EI, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
(4)-e	Commercial Paper Dealer 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.)

Respectfully submitted this 30th day of March, 2007.

R. Alexander Glenn
Deputy General Counsel
Progress Energy Service Company, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: 727-820-5184

Attorney for
PROGRESS ENERGY FLORIDA, INC.

Schedule A

FLORIDA POWER CORPORATION
SELECTED FINANCIAL DATA

CAPITALIZATION:

Florida Power's capitalization at December 31, 2006:

Debt:	Interest Rate		Amount Outstanding
			(in millions)
First Mortgage bonds			
Maturing 2008 through 2033	5.39% (a)	$	1,630
Pollution control refunding revenue bonds			
Secured by Mortgage, Maturing 2018 through 2027	3.66% (a)	$	241
Senior Unsecured Notes			
Maturing 2008	5.77% (a)	$	450
Medium-term notes			
Maturing 2007 through 2028	6.77% (a)	$	241
Borrowing under 5-Year Credit Facility			
Facility Expires 2010	NA (a)	$	-
Discount being amortized over term of bonds		$	(5)
Total long-term debt		$	2,557
Notes payable (Commercial Paper & Credit Facility Borrowings)		$	-
Total debt		$	2,557

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	(b)	$	34
Common stock equity						$	2,687
Total capitalization						$	5,278

(a) Weighted average interest rate at December 31, 2006
(b) Total authorized shares outstanding at December 31, 2006: 335,000

PRE-TAX INTEREST COVERAGE:

Florida Power's pre-tax interest coverage for 2006 was **4.4**

DEBT INTEREST:

Florida Power's debt interest charges for 2006 were **$ 155** million

PREFERRED STOCK DIVIDEND REQUIREMENTS:

Florida Power's preferred stock dividend requirements for 2006 were **$ 1.5** million

Exhibit (1)-f

[EXECUTION COPY]

AMENDMENT

Dated as of May 3, 2006

To the Lenders parties to the Credit Agreement
referred to below

Ladies and Gentlemen:

Reference is made to the Credit Agreement, dated as of March 28, 2005 (the "***Credit Agreement***"), among Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "***Company***"), the Lenders and Bank of America, N.A., as Administrative Agent (the "***Administrative Agent***"). Capitalized terms used herein and not otherwise defined herein have the meanings given such terms in the Credit Agreement. The Company has requested, and the Lenders have agreed, that the Credit Agreement be amended as provided below.

Section 1. Amendments. The parties agree that, subject to the satisfaction of the conditions precedent to effectiveness set forth below, the Credit Agreement is, as of the date hereof, hereby amended as follows:

(a) The following definitions in Section 1.01 are amended and restated in their entirety to read as follows:

""***Applicable Margin***" means on any date, the rate per annum set forth below for the applicable Type of Advance, determined by reference to the ratings assigned to the Reference Securities:

Basis for Pricing	**LEVEL 1** If the Reference Securities are rated at least A- by S&P or at least A3 by Moody's	**LEVEL 2** If the Reference Securities are rated lower than Level 1 but at least BBB+ by S&P or at least Baa1 by Moody's	**LEVEL 3** If the Reference Securities are rated lower than Level 2 but at least BBB by S&P or at least Baa2 by Moody's	**LEVEL 4** If the Reference Securities are rated lower than Level 3 but at least BBB- by S&P or at least Baa3 by Moody's	**LEVEL 5** If the Reference Securities are rated lower than Level 4 or unrated
Eurodollar Rate	0.230%	0.270%	0.350%	0.475%	0.575%
Base Rate	0.0%	0.0%	0.0%	0.0%	0.0%

The Applicable Margin will increase by 0.050% at Levels 1 and 2, by 0.100% at Levels 3 and 4 and by 0.125% at Level 5 at any time that more than 50% of the Commitments are utilized. The Applicable Margin will be redetermined on the date of any change in the rating assigned by S&P or Moody's, as the case may be, to the

Reference Securities. If and so long as an Event of Default shall have occurred and shall be continuing, the Applicable Margin will increase by 2.00%. If the ratings assigned to the Reference Securities by S&P and Moody's are not comparable (*i.e.*, a "split rating"), and (i) the ratings differential is one category, the higher of such two ratings shall control, unless one of the ratings is below BBB- or Baa3, or (ii) the ratings differential is two or more categories or one of the ratings is below BBB- or Baa3, the rating that is one below the higher of the two ratings shall control."

""*Termination Date*" means, with respect to any Lender, the earlier to occur of (i) March 28, 2010, subject to extension to a later date for such Lender pursuant to Section 2.16, and (ii) the date of termination in whole of the Commitments pursuant to Section 2.04 or 6.01."

(b) The following new definitions are inserted in Section 1.01 in appropriate alphabetic order:

""***Additional Commitment Lender***" has the meaning specified in Section 2.16(b)."

""***Anniversary Date***" has the meaning specified in Section 2.16(a)."

""***Current Termination Date***" has the meaning specified in Section 2.16(a)."

""***Declining Lender***" has the meaning specified in Section 2.16(a)."

(c) Section 2.03 is amended and restated in its entirety to read as follows:

*"**SECTION 2.03. Facility Fee.***

The Company agrees to pay to the Administrative Agent for the account of each Lender a facility fee on each Lender's Commitment, irrespective of usage, from the date hereof, in the case of each Bank, and from the effective date specified in the Assignment and Assumption pursuant to which it became a Lender, in the case of each other Lender, until the Termination Date, payable quarterly in arrears on the last day of each March, June, September and December during the term of such Lender's Commitment and on the Termination Date, at a rate per annum determined by reference to the ratings assigned to the Reference Securities as set forth below:

Basis for Pricing	**LEVEL 1** If the Reference Securities are rated at least A- by S&P or at least A3 by Moody's	**LEVEL 2** If the Reference Securities are rated lower than Level 1 but at least BBB+ by S&P or at least Baa1 by Moody's	**LEVEL 3** If the Reference Securities are rated lower than Level 2 but at least BBB by S&P or at least Baa2 by Moody's	**LEVEL 4** If the Reference Securities are rated lower than Level 3 but at least BBB- by S&P or at least Baa3 by Moody's	**LEVEL 5** If the Reference Securities are rated lower than Level 4 or unrated

Facility Fee	0.070%	0.080%	0.100%	0.125%	0.175%

The facility fee rate will be redetermined on the date of any change in the rating assigned by S&P or Moody's, as the case may be, to the Reference Securities. If the ratings assigned to the Reference Securities by S&P and Moody's are not comparable (*i.e.*, a "split rating"), and (i) the ratings differential is one category, unless one of the ratings is below BBB- or Baa3 the higher of such two ratings shall control, or (ii) the ratings differential is two or more categories or one of the ratings is below BBB- or Baa3, the rating that is one below the higher of the two ratings shall control."

(d) The third sentence of Section 2.14(a) is amended and restated in its entirety to read as follows:

"The Administrative Agent will promptly thereafter cause to be distributed like funds relating to the payment of principal or interest or fees (other than pursuant to Section 2.08, 2.12 or 2.16(b)) ratably to the Lenders for the account of their respective Applicable Lending Offices, and like funds relating to the payment of any other amount payable to any Lender to such Lender for the account of its Applicable Lending Office, in each case to be applied in accordance with the terms of this Agreement."

(e) The following is added as a new Section 2.16:

"***SECTION 2.16. Extension of Termination Date.***

(a) So long as no Event of Default shall have occurred and be continuing and the Termination Date shall not have occurred, then at least 30 days but not more than 60 days prior to each of the second and third anniversaries of the date hereof (each, an "***Anniversary Date***"), the Company may request that the Lenders, by written notice to the Administrative Agent (in substantially the form attached hereto as Exhibit F) with a copy to the Arrangers, consent to a one-year extension of the Termination Date. Each Lender shall, in its sole discretion, determine whether to consent to such request and shall notify the Administrative Agent of its determination at least 20 days prior to the applicable Anniversary Date. The failure to respond by any Lender within such time period shall be deemed a denial of such request. The Administrative Agent shall deliver a notice to the Company and the Lenders at least 15 days prior to such Anniversary Date of the identity of the Lenders that have consented to such extension and the Lenders that have declined such consent (the "***Declining Lenders***"). If Lenders holding in the aggregate 50% or less of the Commitments have consented to the requested extension, the Termination Date shall not be extended, and the Commitments of all Lenders shall terminate on the then current Termination Date (the "***Current Termination Date***").

(b) If Lenders holding in the aggregate more than 50% of the Commitments have consented to the requested extension, subject to the conditions set forth in Section 2.16(c), the Termination Date shall be extended as to such consenting Lenders only (and not as to any Declining Lender) for a period of one year following the Current

Termination Date. Unless assigned to another Lender as set forth below, the commitments of the Declining Lenders shall terminate on such Current Termination Date, all Advances of and other amounts payable to such Declining Lenders shall be repaid to them on such Current Termination Date, and such Declining Lenders shall have no further liability as of such Current Termination Date. The Company shall have the right at any time on or before the applicable Anniversary Date to replace each Declining Lender with, and add as "Lenders" under this Agreement in place thereof, one or more Eligible Assignees (each, an "***Additional Commitment Lender***") as provided in Section 8.07(f), each of which Additional Commitment Lenders shall have entered into an Assignment and Acceptance pursuant to which each such Additional Commitment Lender shall, effective as of such Anniversary Date, assume a Commitment (and, if any such Additional Commitment Lender is already a Lender, its Commitment shall be in addition to such Lender's Commitment hereunder on such date) and accept as such Additional Lender's Termination Date with respect to the Commitment so assumed the latest date to which the Termination Date has been extended pursuant to this Section 2.16.

(c) Any extension of the Termination Date pursuant to this Section 2.16 shall become effective upon the applicable Anniversary Date if the Company shall have delivered to the Administrative Agent and each Lender, on or prior to such Anniversary Date, (i) opinions of counsel to the Company substantially in the forms of Exhibits D-3 and D-4 attached hereto upon which each Lender and the Administrative Agent may rely, together with any governmental order referred to therein attached thereto and (ii) a certificate of a duly authorized officer of the Company (the statements contained in which shall be true) to the effect that (x) the representations and warranties contained in Section 4.01 are correct on and as of such Anniversary Date before and after giving effect to the extension of the Termination Date, as though made on and as of such Anniversary Date, and (y) no event has occurred and is continuing, or would result from such extension of the Termination Date, that constitutes an Event of Default or that would constitute an Event of Default but for the requirement that notice be given or time elapse, or both.

(d) Upon the extension of any Termination Date in accordance with this Section 2.16, the Administrative Agent shall deliver to each Lender a revised Schedule II setting forth the Commitment of each Lender after giving effect to such extension, and such Schedule II shall replace the Schedule II in effect before the applicable Anniversary Date."

(f) The first sentence of Section 8.07(f) is amended and restated in its entirety to read as follows:

"If (x) any Lender shall be a Declining Lender, (y) any Lender or any Participant shall make any demand for payment under Section 2.12 or (z) the Company is required to pay any additional amount to any Lender or governmental authority for the account of any Lender pursuant to Section 8.04(c) or (d), then within the time period specified in Section 2.16(b) or within 30 days after such demand for any such payment (if, but only if, such demanded payment has been made by the Company) (as applicable), the Company may, at its sole expense and effort, upon notice to such

Lender and with the approval of the Administrative Agent (which approval shall not be unreasonably withheld or delayed), demand that such Lender assign in accordance with and subject to the restrictions contained in, and consents required by, this Section 8.07 to one or more Eligible Assignees designated by the Company all (but not less than all) of such Lender's Commitment (if any) and the Advances owing to it no later than the applicable Anniversary Date or within the period ending on the later to occur of such 30th day and the last day of the longest of the then current Interest Periods for such Advances (as applicable), *provided* that (i) no Default or Event of Default shall then have occurred and be continuing; (ii) the Company shall have paid to the Administrative Agent the assignment fee specified in Section 8.07(a); (iii) such Lender shall have received payment of an amount equal to the outstanding principal of its Advances, accrued interest thereon, accrued fees and all other amounts payable to it hereunder (including any amounts under Section 8.04(b) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Company (in the case of all other amounts); (iv) in the case of any such assignment resulting from a claim for compensation under Section 2.12 or payments required to be made pursuant to Section 8.04(c) or (d), such assignment will result in a reduction in such compensation or payments thereafter; (v) in the case of any such assignment by a Declining Lender, such Declining Lender shall have consented to such assignment, and (vi) such assignment does not conflict with applicable laws."

(g) Schedule II is amended and restated in its entirety to read as the attached Schedule I hereto.

(h) The attached Exhibit A-1 and Exhibit A-2 hereto are added as "Exhibit D-3" and "Exhibit D-4", respectively, to the Credit Agreement.

(i) The attached Exhibit B hereto is added as "Exhibit F" to the Credit Agreement.

Section 2. Conditions to Effectiveness. Section 1 of this Amendment shall be effective as of the date hereof when and if (i) the Company and the Lenders shall have executed and delivered to the Administrative Agent executed counterparts of this Amendment, and (ii) the representations and warranties of the Company set forth in Section 3 below shall be true and correct on and as of such date of effectiveness as though made on and as of such date.

Section 3. Representations and Warranties. The Company represents and warrants that (i) the representations and warranties contained in Article IV of the Credit Agreement, as amended hereby (with each reference therein to "this Agreement", "hereunder" and words of like import referring to the Credit Agreement being deemed to be a reference to this Amendment and the Credit Agreement, as amended hereby), are true and correct on and as of the date hereof as though made on and as of such date, and (ii) no event has occurred and is continuing, or would result from the execution and delivery of this Amendment, that constitutes an Event of Default.

Section 4. Effect on the Credit Agreement. The execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy of any Lender or the Administrative Agent under the Credit Agreement, nor constitute a waiver of any provision of any of the Credit Agreement. Except as expressly amended above, the Credit Agreement is and shall continue to be in full force and effect and is hereby in all respects ratified and confirmed. This Amendment shall be binding on the parties hereto and their respective successors and permitted assigns under the Credit Agreement.

Section 5. Costs, Expenses and Taxes. The Company agrees to pay on demand all costs and expenses of the Administrative Agent in connection with the preparation, execution and delivery of this Amendment and any other instruments and documents to be delivered hereunder, including, without limitation, the reasonable fees and out-of-pocket expenses of counsel for the Administrative Agent with respect thereto, and all costs and expenses (including, without limitation, counsel fees and expenses), if any, in connection with the enforcement (whether through negotiations, legal proceedings or otherwise) of this Amendment or such other instruments and documents. In addition, the Company agrees to pay any and all stamp and other taxes payable or determined to be payable in connection with the execution and delivery of this Amendment and any other instruments and documents to be delivered hereunder, and agree jointly and severally to save the Lenders and the Administrative Agent harmless from and against any and all liabilities with respect to or resulting from any delay in paying or omission to pay such taxes.

Section 6. Counterparts. This Amendment may be executed in any number of counterparts and by any combination of the parties hereto in separate counterparts, each of which counterparts shall constitute an original, and all of which taken together shall constitute one and the same instrument.

Section 7. Governing Law. This Amendment shall be governed by, and construed in accordance with, the laws of the State of New York.

[Remainder of page intentionally left blank]

If you consent and agree to the foregoing, please evidence such consent and agreement by executing and faxing one copy, and returning six counterparts, of this Amendment to King & Spalding LLP, 1185 Avenue of the Americas, New York, New York 10036, Attention: Colleen Stapleton (fax no. 212-556-2222) no later than 5:00 p.m., New York City time, on May 3, 2006.

Very truly yours,

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

By ________________________
Name: Thomas R. Sullivan
Title: Treasurer

The undersigned hereby consent
and agree to the foregoing:

BANK OF AMERICA, N.A.,
as Administrative Agent

By Maria A. McClain
Name: Maria A. McClain
Title: Vice President

BANK OF AMERICA, N.A., as Lender

By ~~GMillhorn~~

Name: Gabriela Millhorn
Title: Senior Vice President

BARCLAYS BANK PLC, as Lender

By____________________________
Name: Sydney G. Dennis
Title: Director

THE BANK OF NEW YORK, as Lender

By______________________________
Name: David Sunderwirth
Title: Vice President

CITIBANK, N.A., as Lender

By________________________________
Name:
Title:

STUART J. GLEN
Director

MELLON BANK, N.A., as Lender

By______________________________
Name: Thomas J. Tarasovich, Jr.
Title: Assistant Vice President

JPMORGAN CHASE BANK, N.A., as Lender

By______________________________
Thomas L. Casey
Vice President

DEUTSCHE BANK AG
NEW YORK BRANCH, as Lender

By______________________________
Name: Marcus Tarkington
Title: Director

By______________________________
Name: Rainer Meier
Title: Vice President

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD., NEW YORK BRANCH (as successor-by-merger to UFJ BANK LIMITED), as Lender

By Linda Tam
Name: Linda Tam
Title: Authorized Signatory

WACHOVIA BANK, N.A., as Lender

By ______________________________
Name: Lawrence N. Gross
Title: Assistant Vice President

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD., NEW YORK BRANCH (formerly known as THE BANK OF TOKYO-MITSUBISHI, LTD., NEW YORK BRANCH), as Lender

By Linda Tam

Name: Linda Tam
Title: Authorized Signatory

SUNTRUST BANK, as Lender

By Kelley B. Brandenburg
Name: Kelley B. Brandenburg
Title: Vice President

SCHEDULE I

SCHEDULE II

Commitments

Lender	Commitment	Domestic Lending Office	Eurodollar Lending Office
Bank of America, N.A.	$ 70,000,000	901 Main Street, 14th Fl. Mail Code: TX1-492-14-12 Dallas, TX 75202-3714 Attention: Jacqueline R. Archuleta Telephone: 214.209.2135 Telecopier: 214.290.8372 Email: jacqueline.archuleta@bankofamerica.com	Same as Domestic Lending Office
Barclays Bank PLC	$ 70,000,000	Barclays Capital Services, LLC 200 Cedar Knolls Road Whippany, NJ 07981 Attention: Erik Hoffman Telephone: 973.576.3709 Telecopier: 973.576.3014 Email: erik.hoffman@barcap.com	Same as Domestic Lending Office
The Bank of Tokyo-Mitsubishi, Ltd., New York Branch	$ 60,000,000	BTM Information Services, Inc. c/o The Bank of Tokyo-Mitsubishi, Ltd., NY Branch 1251 Avenue of the Americas, 12th Floor New York, NY 10020-1104 Attention: Rolando Uy, AVP, Loan Operations Dept. Telephone: 201.413.8570 Telecopier: 201.521.2304 Email: N/A	Same as Domestic Lending Office
Deutsche Bank AG New York Branch	$ 45,000,000	60 Wall Street New York, NY 10005 Attention: Russell Johnson Telephone: 832.239.4622 Telecopier: 832.239.4693 Email: russell.johnson@db.com	Same as Domestic Lending Office

Lender	Commitment	Domestic Lending Office	Eurodollar Lending Office
SunTrust Bank	$ 45,000,000	SunTrust Bank Mail Code 1929 303 Peachtree Street, 10th Floor Atlanta, GA 30308 Attn: Tina Marie Edwards Telephone: 404-588-8660 Telecopier: 404-588-4402 Email: tinamarie.edwards@suntrust.com	Same as Domestic Lending Office
JPMorgan Chase Bank, N.A.	$ 40,000,000	1111 Fannin – 10 Houston, TX 77002 Attention: Kelly Collins, Account Manager Telephone: 713.750.2530 Telecopier: 713.427.6307 Email: kelly.collins@jpmchase.com	Same as Domestic Lending Office
Wachovia Bank, N.A.	$ 40,000,000	201 South College Street Charlotte NC 28288-0680 Attention: Jeremy Collins, Analyst Telephone: 704.715.7682 Telecopier: 704.715.0091 E-Mail: jeremy.collins1@wachovia.com	Same as Domestic Lending Office
Citibank, N.A.	$ 35,000,000	388 Greenwich Street New York, New York 10013 Attention: Stuart Glen Telephone: 212.816-8553 Telecopier: 212.816-8098 Email: stuart.j.glen@citigroup.com	Same as Domestic Lending Office
Mellon Bank, N.A.	$ 25,000,000	525 William Penn Place Room 153-1203 Pittsburgh, PA 15259-0003 Attention: Daria Armen, Loan Administrator Telephone: 412.234.1870 Telecopier: 412.209.6117 Email: N/A	Same as Domestic Lending Office
The Bank of New York	$ 20,000,000	One Wall Street 19th Floor New York, NY 10286 Attention: Frank Su, Energy Division Telephone: 212.635.7532 Telecopier: 212.635.7552 Email: fsu@bankofny.com	Same as Domestic Lending Office
Total:	$ 450,000,000		

EXHIBIT A-1

EXHIBIT D-3

FORM OF OPINION OF GENERAL COUNSEL TO THE BORROWER UPON EXTENSION OF THE TERMINATION DATE

__________ ___, 20__

To each of the Lenders parties to the Credit Agreement referred to below and to Bank of America, N.A., as Administrative Agent

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

Ladies and Gentlemen:

This opinion is furnished to you by me as Associate General Counsel of Progress Energy Service Company, LLC and in my capacity as counsel to Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "***Borrower***") in connection with the extension of the Termination Date until ________ __, _____ under Section 2.16 (the "***Extension***") of the Credit Agreement, dated as of March 28, 2005, as amended, (the "***Credit Agreement***", the terms defined therein being used herein as therein defined), among the Borrower, certain lenders from time to time parties thereto (the "***Lenders***") and Bank of America, N.A., as Administrative Agent for the Lenders.

In connection with the Extension, I have examined:

(1) The Credit Agreement.

(2) The documents furnished by the Borrower pursuant to Section 3.01 of the Credit Agreement.

(3) The Request for Extension of Termination Date and Certificate, dated _____, submitted by the Borrower in connection with the Extension.

(4) The Amended Articles of Incorporation of the Borrower and all amendments thereto (the "***Charter***").

(5) The By-Laws of the Borrower and all amendments thereto (the "***By-Laws***").

I have also examined the originals, or copies of such other corporate records of the Borrower, certificates of public officials and of officers of the Borrower and agreements, instruments and other documents as I have deemed necessary as a basis for the opinions expressed below. As to questions of fact material to such opinions, I have, when relevant facts were not independently established by me, relied upon certificates of the Borrower or its officers or of public officials. I have assumed the authenticity of all documents submitted to me as originals, the conformity to originals of all documents submitted as certified or photostatic copies and the authenticity of the signatures (other than those of the Borrower), and the due execution and delivery, pursuant to due authorization, of the Credit Agreement by the Lenders and the Administrative Agent and the validity and binding effect thereof on such parties. For purposes of my opinions expressed in paragraph 1 below as to existence and good standing, I have relied as of their respective dates on certificates of public officials, copies of which are attached hereto as Exhibit A. Whenever the phrase "to my knowledge" is used in this opinion it refers to my actual knowledge and the actual knowledge of the attorneys who work under my supervision and who were involved in the representation of the Borrower in connection with the transactions contemplated by the Credit Agreement.

I or attorneys working under my supervision are qualified to practice law in the State of Florida and the opinions expressed herein are limited to the law of the State of Florida and the Federal law of the United States.

Based upon the foregoing and upon such investigation as I have deemed necessary, I am of the following opinion:

1. The Borrower is a corporation duly organized, validly existing and in good standing under the laws of the State of Florida.

2. The execution, delivery and performance by the Borrower of the Credit Agreement, after giving effect to the Extension, are within the Borrower's corporate powers, have been duly authorized by all necessary corporate action, and do not violate (i) the Charter or the By-Laws or any law, rule or regulation applicable to the Borrower (including, without limitation, Regulation X of the Board of Governors of the Federal Reserve System) or (ii) result in breach of, or constitute a default under, any judgment, decree or order binding on the Borrower, or any indenture, mortgage, contract or other instrument to which it is a party or by which it is bound. The Credit Agreement has been duly executed and delivered on behalf of the Borrower.

3. No authorization, approval or other action by, and no notice to or filing with any governmental authority or regulatory body is required for the due execution, delivery and performance, by the Borrower of the Credit Agreement, after giving effect to the Extension, other than a notification to the Florida Public Service Commission, which has been timely made.

4. To my knowledge, except as described in the reports and registration statements that the Borrower has filed with the Securities and Exchange Commission, there are no pending or overtly threatened actions or proceedings against the Borrower or any of the Subsidiaries before any court, governmental agency or arbitrator, that may materially adversely affect the financial condition, operations or properties of the Borrower and its Subsidiaries, taken as a whole.

The opinions set forth above are subject to the qualification that no opinion is expressed herein as to the enforceability of the Credit Agreement or any other document.

The foregoing opinions are solely for your benefit and may not be relied upon by any other Person other than any other Person that may become a Lender under the Credit Agreement after the date hereof and Hunton & Williams LLP, in connection with their opinion delivered on the date hereof under Section 2.16(c) of the Credit Agreement. This letter speaks only as of the date hereof and may not be relied on by any person with respect to any date after the date hereof. I do not undertake to advise you of any changes in the opinions expressed herein from matters that may hereafter arise or be brought to my attention.

Very truly yours,

<u>EXHIBIT A-2</u>

EXHIBIT D-4

FORM OF OPINION OF SPECIAL COUNSEL TO THE BORROWER UPON EXTENSION OF THE TERMINATION DATE

__________ ___, 20__

To each of the Lenders parties to the Credit Agreement referred to below and to Bank of America, N.A., as Administrative Agent

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

Ladies and Gentlemen:

This opinion is furnished to you by us as counsel for Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "***Borrower***") in connection with the extension of the Termination Date until March [ ], 20___ under Section 2.16 (the "***Extension***") of the Credit Agreement, dated as of March 28, 2005, as amended, (the "***Credit Agreement***", the terms defined therein being used herein as therein defined), among the Borrower, certain lenders from time to time parties thereto (the "***Lenders***") and Bank of America, N.A., as Administrative Agent for the Lenders.

In connection with the Extension, we have examined:

(1) The Credit Agreement.

(2) The documents furnished by the Borrower pursuant to Section 3.01 of the Credit Agreement.

(3) The Request for Extension of Termination Date and Certificate, dated _____, submitted by the Borrower in connection with the Extension.

(4) The opinion letter of even date herewith, addressed to you by __________, counsel to the Borrower and delivered in connection with the transactions contemplated by the Credit Agreement (the "***Borrower Opinion Letter***").

We have also examined the originals, or copies of such other corporate records of the Borrower, certificates of public officials and of officers of the Borrower and agreements, instruments and other documents as we have deemed necessary as a basis for the opinions expressed below. As to questions of fact material to such opinions, we have, when relevant facts were not independently established by us, relied upon certificates of the Borrower or its officers or of public officials. We have assumed the authenticity of all documents submitted to us as originals, the conformity to originals of all documents submitted as certified or photostatic copies and the authenticity of the originals (other than those of the Borrower), and the due execution and delivery, pursuant to due authorization, of the Credit Agreement by the Lenders and the Administrative Agent and the validity and binding effect thereof on such parties. Whenever the phrase "to our knowledge" is used in this opinion it refers to the actual knowledge of the attorneys of this firm involved in the representation of the Borrower without independent investigation.

We are qualified to practice law in the States of Florida and New York, and the opinions expressed herein are limited to the law of the States of Florida and New York applicable to public utilities and the federal law of the United States. To the extent that our opinions expressed herein depend upon opinions expressed in paragraphs 1 through 4 of the Borrower Opinion Letter, we have relied without independent investigation on the accuracy of the opinions expressed in the Borrower Opinion Letter, subject to the assumptions, qualifications and limitations set forth in the Borrower Opinion Letter.

Based upon the foregoing and upon such investigation as we have deemed necessary, we are of the following opinion the Credit Agreement after giving effect to the Extension constitutes the valid and binding obligation of the Borrower enforceable against the Borrower in accordance with its terms except as enforcement may be limited or otherwise affected by (a) bankruptcy, insolvency, reorganization, fraudulent transfer, moratorium or other similar laws affecting the rights of creditors generally and (b) principles of equity, whether considered at law or in equity.

The opinion set forth above is subject to the following qualifications:

(a) In addition to the application of equitable principles described above, courts have imposed an obligation on contracting parties to act reasonably and in good faith in the exercise of their contractual rights and remedies, and may also apply public policy considerations in limiting the right of parties seeking to obtain indemnification under circumstances where the conduct of such parties is determined to have constituted negligence.

(b) No opinion is expressed herein as to (i) Section 8.05 of the Credit Agreement, (ii) the enforceability of provisions purporting to grant to a party conclusive rights of determination, (iii) the availability of specific performance or other equitable remedies, (iv) the enforceability of rights to indemnity under federal or state securities laws or (v) the enforceability of waivers by parties of their respective rights and remedies under law.

(c) No opinion is expressed herein as to provisions, if any, in the Credit Agreement, which (A) purport to excuse, release or exculpate a party for liability for or indemnify a party against the consequences of its own acts, (B) purport to make void any act done in contravention thereof, (C) purport to authorize a party to make binding determinations in its sole discretion, (D) relate to the effects of laws which may be enacted in the future, (E) require waivers, consents or amendments to be made only in writing, (F) purport to waive rights of offset or to create rights of set off other than as provided by statute, or (G) purport to permit acceleration of indebtedness and the exercise of remedies by reason of the occurrence of an immaterial breach of the Credit Agreement or any related document. Further, we express no opinion as to the necessity for any

Lender, by reason of such Lender's particular circumstances, to qualify to transact business in the State of New York or as to any Lender's liability for taxes in any jurisdiction.

The foregoing opinion is solely for your benefit and may not be relied upon by any other Person other than any other Person that may become a Lender under the Credit Agreement after the date hereof in accordance with the provisions thereof. This letter speaks only as of the date hereof and may not be relied on by any person with respect to any date after the date hereof. We do not undertake to advise you of any changes in the opinions expressed herein from matters that may hereafter arise or be brought to our attention.

Very truly yours,

EXHIBIT B

EXHIBIT F

FORM OF REQUEST FOR EXTENSION OF THE TERMINATION DATE

CREDIT AGREEMENT

Dated as of March 28, 2005

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

and

THE BANKS LISTED ON THE SIGNATURE PAGES HEREOF
(Banks)

and

OTHER LENDERS FROM TIME TO TIME
PARTY HERETO
(Lenders)

and

BANK OF AMERICA, N.A.
(Administrative Agent)

Request for Extension of Termination Date

I, [______________], [________________] of Progress Energy Florida, Inc., do hereby request that the Termination Date of the Credit Agreement, dated as of March 28, 2005, as amended (the "***Credit Agreement***", the terms defined therein being used herein as therein defined), among Progress Energy Florida, Inc., certain Lenders from time to time parties thereto and Bank of America, N.A., as Administrative Agent for the Lenders, be extended for a one-year period (hereinafter the "***Proposed Extension***") pursuant to Section 2.16 of the Credit Agreement and, in connection therewith, hereby certify as follows:

(i) as of the date hereof, the representations and warranties set forth in Section 4.01 (including without limitation those regarding any required approvals of or notices to governmental bodies) of the Credit Agreement are and will be as of the effective date of the Proposed Extension accurate both before and after giving effect to the Proposed Extension; and

(ii) as of the date hereof, no Event of Default has occurred, nor has any event occurred, that with the giving of notice or the passage of time or both, would constitute an Event of Default, in either case both before and after giving effect to the Proposed Extension.

Witness my hand this ______ day of _________, ____.

____

[__________________]

<u>Exhibit No. (3) – c</u>

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, 2006

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
	Progress Energy	
1-15929	**Progress Energy, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-2155481
1-3382	**Carolina Power & Light Company** **d/b/a Progress Energy Carolinas, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-0165465
1-3274	**Florida Power Corporation** **d/b/a Progress Energy Florida, Inc.** 299 First Avenue North St. Petersburg, Florida 33701 Telephone: (727) 820-5151 State of Incorporation: Florida	59-0247770

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

Title of each class	Name of each exchange on which registered
Progress Energy, Inc.:	
Common Stock (Without Par Value)	New York Stock Exchange
Carolina Power & Light Company:	None
Florida Power Corporation:	None

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

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

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

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

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

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

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

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

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

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

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

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

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

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

As of June 30, 2006, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $10,832,028,534. As of June 30, 2006, 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, 2006, 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, 2007, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	257,109,374
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 2007 Annual Meeting of Shareholders are incorporated into PART III, Items 10, 11, 12 , 13 and 14 hereof.

This combined Form 10-K is filed separately by three registrants: Progress Energy, PEC and PEF (collectively, the Progress Registrants). Information contained herein relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants.

PEF meets the conditions set forth in General Instruction I (1) (a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format permitted by General Instruction I (2) to such Form 10-K.

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

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

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings and Stock Ownership Plan
AFUDC	Allowance for funds used during construction
AHI	Affordable housing investment
AOCI	Accumulated other comprehensive income, a component of common stock equity
ARO	Asset retirement obligation
Annual Average Price	Average wellhead price per barrel for unregulated domestic crude oil for the year
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Bcf	Billion cubic feet
Broad River	Broad River LLC's Broad River Facility
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCO	Former Progress Ventures segment's nonregulated Competitive Commercial Operations
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Clean Smokestacks Act	North Carolina Clean Smokestacks Act, enacted in June 2002
Coal	Coal terminals and marketing operations that blend and transload coal as part of the transportation network for coal delivery
Coal and Synthetic Fuels	Business segment primarily engaged in synthetic fuels production and sales operations, the operation of synthetic fuels facilities for third parties and coal terminal services
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Colona	Colona Synfuel Limited Partnership, LLLP
Corporate	Collectively, the Parent, PESC and consolidation entities
Corporate and Other	Corporate and Other segment includes Corporate as well as other nonregulated businesses
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's coal-fired steam turbines Crystal River Units No. 4 and 5
CUCA	Carolina Utility Customers Association
CVO	Contingent value obligation
DeSoto	DeSoto County Generating Co., LLC
DIG Issue C20	FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature"
Dixie Fuels	Dixie Fuels Limited
DOE	United States Department of Energy

Earthco	Four wholly owned coal-based solid synthetic fuels limited liability companies
ECRC	Environmental Cost Recovery Clause
EIA	Energy Information Agency
Energy Delivery	Distribution operations of the Utilities
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERO	Electric reliability organization
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FIN 46R	FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143"
FIN 48	FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"
Fitch	Fitch Ratings
Florida Global Case	U.S. Global LLC v. Progress Energy, Inc. et al
Florida Progress	Florida Progress Corporation, one of our wholly owned subsidiaries
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
Gas	Former Progress Ventures segment's natural gas drilling and production business
the Georgia Contracts	Fixed price full-requirement contracts serviced by CCO
Georgia Power	Georgia Power Company, a subsidiary of Southern Company
Georgia Region	Reporting unit consisting of our Effingham, Monroe, Walton and Washington nonregulated generation plants in service
Global	U.S. Global LLC
Gulfstream	Gulfstream Gas System, L.L.C.
Harris	PEC's Shearon Harris Nuclear Plant
IBEW	International Brotherhood of Electrical Workers
IRS	Internal Revenue Service
kV	Kilovolt
kVA	Kilovolt-ampere
kWh/s	Kilowatt-hour/s
Level 3	Level 3 Communications, Inc.
LIBOR	London Inter Bank Offering Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in Part II, Item 7 of this Form 10-K
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured gas plant
MW	Megawatts
MWh/s	Megawatt-hour/s
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NCDWQ	North Carolina Division of Water Quality
NCNG	North Carolina Natural Gas Corporation
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Council
NOPR	Notice of Proposed Rulemaking
the Notes Guarantee	Florida Progress' full and unconditional guarantee of the Subordinated Notes
NOx	Nitrogen Oxide
NOx SIP Call	EPA rule which requires 22 states including North Carolina, South Carolina and Georgia (but excluding Florida) to further reduce nitrogen oxide emissions

NSR	New Source Review requirements by the EPA
NRC	United States Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance expense
OCI	Other comprehensive income
OPC	Florida's Office of Public Counsel
OPEB	Postretirement benefits other than pensions
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Progress Energy Carolinas, Inc., formerly referred to as Carolina Power & Light Company
PEF	Progress Energy Florida, Inc., formerly referred to as Florida Power Corporation
PESC	Progress Energy Service Company, LLC
the Phase-out Price	Price per barrel of unregulated domestic crude oil at which Section 29/45K tax credits are fully eliminated
PM 2.5	EPA standard for particulate matter less than 2.5 microns in diameter
PM 2.5-10	EPA standard for particulate matter between 2.5 and 10 microns in diameter
PM 10	EPA standard for particulate matter less than 10 microns in diameter
Power Agency	North Carolina Eastern Municipal Power Agency
Preferred Securities	7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A issued by the Trust
Preferred Securities Guarantee	Florida Progress' guarantee of all distributions related to the Preferred Securities
Progress Affiliates	Five affiliated synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The reporting registrants within the Progress Energy consolidated group. Collectively, Progress Energy, Inc., PEC and PEF
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
Progress Rail	Progress Rail Services Corporation
Progress Ventures	Former business segment that primarily engaged in nonregulated energy generation, energy marketing activities and natural gas drilling and production
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PTC	Progress Telecommunications Corporation
PT LLC	Progress Telecom, LLC
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utilities Regulatory Policies Act of 1978
PVI	Progress Energy Ventures, Inc., formerly referred to as Progress Ventures, Inc.
PWC	Public Works Commission of the City of Fayetteville, N.C.
QF	Qualifying facility
RCA	Revolving credit agreement
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
Rowan	Rowan County Power, LLC
RSA	Restricted stock awards program
RTO	Regional transmission organization
SAB 108	SEC Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"
SCPSC	Public Service Commission of South Carolina
Scrubber	A device that neutralizes sulfur compounds formed during coal combustion
SEC	United States Securities and Exchange Commission
Section 29	Section 29 of the Code

Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 316(b)	Section 316(b) of the Clean Water Act
Section 45K	Section 45K of the Code
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART II, Item 8 of this Form 10-K
SESH	Southeast Supply Header, L.L.C.
S&P	Standard & Poor's Rating Services
SFAS	Statement of Financial Accounting Standards
SFAS No. 5	Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies"
SFAS No. 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 87	Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes"
SFAS No. 115	Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS No. 123	Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"
SFAS No. 123R	Statement of Financial Accounting Standards No. 123R, "Share-Based Payment"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative and Hedging Activities"
SFAS No. 142	Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets"
SFAS No. 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations"
SFAS No. 144	Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS No. 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements"
SFAS No. 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"
SNG	Southern Natural Gas Company
SO_2	Sulfur dioxide
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Threshold Price	Price per barrel of unregulated domestic crude oil at which Section 29/45K tax credits begin to be reduced
the Trust	FPC Capital I, a wholly owned subsidiary of Florida Progress
the Utilities	Collectively, PEC and PEF
Winchester Production	Winchester Production Company, Ltd.
Winter Park	City of Winter Park, Fla.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

In this combined report, each of the Progress Registrants makes forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The matters discussed throughout this combined Form 10-K that are not historical facts are forward looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and the Progress Registrants undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

In addition, examples of forward-looking statements discussed in this Form 10-K include, but are not limited to, 1) statements made in PART I, Item 1A, "Risk Factors" and 2) PART II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) including, but not limited to, statements under the following headings: a) "Strategy" about our future strategy and goals; b) "Results of Operations" about trends and uncertainties; c) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2009 and future financing plans; and d) "Other Matters" about our synthetic fuels facilities, the effects of new environmental regulations, nuclear decommissioning costs and the effect of electric utility industry restructuring.

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; the financial resources and capital needed to comply with environmental laws and our ability to recover eligible costs under cost-recovery clauses; weather conditions that directly influence the production, delivery and demand for electricity; the ability to recover through the regulatory process costs associated with future significant weather events; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; economic fluctuations and the corresponding impact on our commercial and industrial customers; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the impact on our facilities and businesses from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the ability to successfully access capital markets on favorable terms; the Progress Registrants' ability to maintain their current credit ratings and the impact on the Progress Registrants' financial condition and ability to meet their cash and other financial obligations in the event their credit ratings are downgraded; the impact that increases in leverage may have on each of the Progress Registrants; the impact of derivative contracts used in the normal course of business; the investment performance of our pension and benefit plans; the Progress Registrants' ability to control costs, including pension and benefit expense, and achieve our cost-management targets for 2007; our ability to generate and utilize tax credits from the production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); the impact that future crude oil prices may have on our earnings from our coal-based solid synthetic fuels businesses; the execution of our announced intent to dispose of our Competitive Commercial Operations (CCO) business and additional resulting charges to income, which could exceed $200 million; our ability to manage the risks involved with the CCO business, including dependence on third parties and related counterparty risks, until completion of our disposal strategy; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in the Progress Registrants' filings with the United States Securities and Exchange Commission (SEC). Many, but not all, of the factors that may impact actual results are discussed in Item 1A, "Risk Factors," which you should carefully read. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on the Progress Registrants.

PART I

ITEM 1. BUSINESS

GENERAL

ORGANIZATION

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

The Parent was incorporated on August 19, 1999 initially as CP&L Energy, Inc. and became the holding company for PEC on June 19, 2000. All shares of common stock of PEC were exchanged for an equal number of shares of CP&L Energy, Inc. common stock. On November 30, 2000, we completed our acquisition of Florida Progress Corporation (Florida Progress), a diversified, exempt electric utility holding company whose primary subsidiaries are PEF and Progress Fuels Corporation (Progress Fuels). In the $5.4 billion purchase transaction, we paid cash consideration of approximately $3.5 billion and issued 46.5 million shares of common stock valued at approximately $1.9 billion. In addition, we issued 98.6 million contingent value obligations (CVOs) valued at approximately $49 million. Prior to February 8, 2006, the Parent was a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA 1935). Effective February 8, 2006, the Federal Energy Regulatory Commission (FERC) was provided with new oversight responsibilities for the electric utility industry by the Public Utility Holding Company Act of 2005 (PUHCA 2005) as discussed below.

Our wholly owned regulated subsidiaries, PEC and PEF, each a business segment, are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. We have approximately 21,300 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. The Utilities operate in retail service territories that are anticipated to have population growth higher than the U.S. average. In addition, PEC's greater proportion of commercial and industrial customers, combined with PEF's greater proportion of residential customers, creates a balanced customer base. We are dedicated to meeting the growth needs of our service territories and delivering reliable, competitively priced energy from a diverse portfolio of power plants.

Our nonregulated Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (the Code), the operation of synthetic fuels facilities for third parties as well as coal terminal services. Our terminal operations support our synthetic fuels operations for the procuring and processing of coal and the transloading and marketing of synthetic fuels. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding synthetic fuels production. During September and October 2006, we resumed limited synthetic fuels production at our facilities, which continued through the end of 2006. The tax credit program for production of qualifying synthetic fuels is scheduled to expire at the end of 2007.

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

As discussed in "Significant Developments" below, many of our nonregulated business operations have been divested or are in the process of being divested. Consequently, we no longer report a Progress Ventures segment and the composition of other continuing segments has been impacted by these divestitures. See Note 19 for information regarding the revenues, income and assets attributable to our business segments.

For the year ended December 31, 2006, our consolidated revenues were $9.6 billion and our consolidated assets at year-end were $25.7 billion.

SIGNIFICANT DEVELOPMENTS

As discussed more fully in Note 3 and under MD&A – "Discontinued Operations," we divested, or announced divestitures, of multiple nonregulated businesses during 2006 in accordance with our business strategy to reduce our business risk from nonregulated operations and to focus on the core operations of the Utilities. The 2006 divestitures resulted in net cash proceeds of $1.654 billion, which were used primarily to reduce debt, and for other corporate purposes. As discussed in Note 3, certain of our divestiture transactions announced in 2006 are anticipated to close in 2007 and we anticipate recording charges in excess of $200 million after-tax related to these divestitures. Prior to 2006, the divested entities had been included within the following segments:

Former Progress Ventures segment:

- CCO – Georgia Operations
- CCO – Operations of DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan) generation facilities
- Natural gas drilling and production business (Gas)

Coal and Synthetic Fuels segment:

- Dixie Fuels Limited (Dixie Fuels)
- Progress Materials, Inc.

Corporate and Other segment:

- Progress Telecom, LLC (PT LLC)

In addition to the divestitures and acquisitions discussed in Notes 3 and 4, we also completed the following transactions during the five-year period ended December 31, 2006:

- During 2003, we sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds were approximately $97 million. During 2006, we sold our remaining Gas operations.

- During 2003, two wholly owned subsidiaries of Progress Energy and a wholly owned subsidiary of Odyssey Telecorp, Inc. contributed substantially all of their assets and transferred certain liabilities to PT LLC. Following a series of transactions, Progress Telecommunications Corporation (PTC) held a 51 percent ownership interest in, and was the parent of, PT LLC. PTC sold its interest in PT LLC in 2006.

- During 2003, Progress Fuels entered into several unrelated transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (Bcf) from four companies headquartered in Texas. The total cash purchase price for the transactions was $168 million.

- During 2003, we entered into a definitive agreement with Williams Energy Marketing and Trading, a subsidiary of The Williams Companies, Inc., to acquire, for a cash payment of $188 million, a long-term full requirements power supply agreement at fixed prices with Jackson Electric Membership Corporation, located in Jefferson, Ga. We anticipate that a third party will acquire this contract as part of our CCO divestiture strategy.

AVAILABLE INFORMATION

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

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

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

COMPETITION

REGULATED UTILITIES

RETAIL COMPETITION

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give 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.

WHOLESALE COMPETITION

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

Increased competition in the wholesale electric utility industry and the availability of transmission access could affect the Utilities' load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of the Utilities to retain current wholesale customers who have existing contracts with PEC or PEF.

On August 8, 2005, the Energy Policy Act of 2005 (EPACT) was signed into law. This federal law contained key provisions affecting the electric power industry, including competition among generators of electricity. The FERC has implemented and is considering a number of related regulations to implement EPACT that may impact, among other things, requirements for reliability, Qualified Facilities (QFs), transmission information availability, transmission congestion, security constrained dispatch, energy market transparency, energy market manipulation and behavioral rules.

In addition to EPACT, other policies and orders issued by the FERC have supported increased competition within the electric generation industry. EPACT clarified and expanded the FERC's authority to assure that markets operate fairly without imposing new, mandatory intrusion on state authorities. On February 15, 2007, the FERC adopted Order 890, which reforms the open-access transmission regulatory framework previously established under Orders 888 and 889. Order 890 is designed to ensure that transmission service is provided on a nondiscriminatory and just and reasonable basis, as well as provide for more effective regulation and transparency in the operation of the transmission grid. We are currently evaluating the expected impact on our operations from compliance with Order 890.

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. In July 2004, the FERC issued a second order that re-affirmed its April order and initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. The Utilities do not have market-based rate authority for wholesale sales in peninsular Florida.

Given the difficulty PEC believed it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting PEC to sales outside of PEC's control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs.

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

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

REGIONAL TRANSMISSION ORGANIZATIONS

The FERC's Order 2000, issued in late 1999, established national standards for regional transmission organizations (RTOs) and advocated the view that regulated, unbundled transmission would facilitate competition in both wholesale and retail electricity markets. In October 2000, as a result of FERC Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of the GridSouth RTO. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the Southeast engage in mediation to develop a plan for a single RTO for the Southeast. PEC participated in the mediation; no consensus was reached on creating a Southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC's investment in GridSouth totaled $33 million at December 31, 2006. PEC expects to recover this investment.

Also as a result of FERC Order 2000, PEF, Florida Power & Light Company and Tampa Electric Company collectively filed an application with the FERC in October 2000 for approval of the GridFlorida RTO for peninsular Florida. In 2002, the Florida Public Service Commission (FPSC) approved many of the aspects of a modified GridFlorida structure and held workshops in 2004 to address other GridFlorida issues. A cost-benefit study performed by an independent consulting firm concluded in 2005 that the GridFlorida RTO was not cost effective. The study further segregated the costs and benefits between FPSC jurisdictional and nonjurisdictional customers, concluding that the jurisdictional customers would incur even more costs, and benefits would be shifted to nonjurisdictional customers. In light of the findings and conclusions of the cost-benefit study, during 2006 the GridFlorida docketed proceedings were closed by both the FPSC and the FERC, and GridFlorida was dissolved. PEF fully recovered its startup costs in GridFlorida from retail ratepayers through base rates.

FRANCHISE MATTERS

PEC has nonexclusive franchises with varying expiration dates in most of the municipalities in North Carolina and South Carolina in which it distributes electricity. The general effect of these franchises is to provide for the manner in which PEC occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. Of these 239 franchises, the majority covers 60-year periods from the date enacted, and 45 have no specific expiration dates. Of the franchise agreements with expiration dates, three expire during the period January 1, 2007 through December 31, 2011, and the remainder expires between January 1, 2012 and 2061. PEC also provides service within a number of municipalities and in all of its unincorporated areas without franchise agreements.

PEF has nonexclusive franchises with varying expiration dates in 110 of the Florida municipalities in which it distributes electricity. PEF also provides service to 12 other municipalities and in all of its unincorporated areas without franchise agreements. The general effect of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. The franchise agreements cover periods ranging from 10 to 30 years with the majority covering 30-year periods from the date enacted. Of the 110 franchise agreements, three expire between January 1, 2007 and December 31, 2011, and the remainder expires between January 1, 2012 and December 31, 2036.

STRANDED COSTS

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 QFs. Thus far, all states that have passed restructuring legislation have provided for the opportunity to recover a substantial portion of stranded costs. Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions, including the future price of electricity.

Our largest stranded cost exposure is for PEF's purchased power commitments with QFs, under which PEF has future minimum expected capacity payments through 2033 of $4.930 billion (See Note 22A). PEF was obligated to enter into these contracts under provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA). PEF continues to seek ways to address the impact of escalating payments under these contracts. However, the FPSC allows for full recovery of the retail portion of the cost of power purchased from QFs. PEC does not have significant future minimum expected capacity payments under their purchased power commitments with QFs.

EPACT repealed the mandatory purchase and sales requirements of PURPA in competitive markets as determined by the FERC. The law also requires the FERC to revise the criteria for new QFs and removes the ownership limitations on QFs. On October 20, 2006, the FERC issued a final rule to implement a provision from EPACT that provides for termination of an electric utility's obligation to enter into new power purchase contracts with a QF if the FERC makes specific findings about the QF's access to competitive markets. The order establishes a rebuttable presumption that any utility located in areas covered by certain RTOs (neither PEC nor PEF are within these specified areas) will be relieved from the must-buy requirement with respect to QFs larger than 20 MW. With respect to other markets, and with respect to all QFs 20 MW or smaller, the utility bears the burden of showing that it qualifies for relief from the must-buy requirement. Any electric utility seeking relief from the must-buy requirements, regardless of location, must apply to the FERC for relief. If the must-buy requirement is terminated in an electric utility's service territory, QFs, state agencies, or others may later petition for reinstatement of the requirement if circumstances change. The final rule went into effect January 2, 2007. We cannot predict at this time what impact this rule will have on our business.

NONREGULATED BUSINESSES

Coal and Synthetic Fuels operations compete in the steam and industrial coal markets of the eastern United States. Factors contributing to success in these markets include a competitive cost structure and strategic locations. There are, however, numerous competitors in each of these markets, although no one competitor is dominant in any industry. As discussed previously, we idled our synthetic fuels facilities for a portion of 2006 due to uncertainty surrounding synthetic fuels production. The tax credit program for production of qualifying synthetic fuels is scheduled to expire at the end of 2007.

Our CCO business, anticipated to be divested during 2007, operates in the nonregulated wholesale market where competitive pricing is the primary driver.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

As a result of the acquisition of Florida Progress, Progress Energy was a registered public utility holding company subject to regulation by the SEC under PUHCA 1935, including provisions relating to the issuance of securities, sales, acquisitions of securities and utility assets, and services performed by PESC. Effective February 8, 2006, EPACT provisions repealed PUHCA 1935 and enacted PUHCA 2005. Subsequent to that date, the Parent is subject to regulation by the FERC as a public utility holding company rather than by the SEC. EPACT granted the FERC certain new powers, previously addressed under PUHCA 1935, including accounting and record retention authority and cost allocation jurisdiction at the election of the holding company system or the state utility commissions with jurisdiction over its utility subsidiaries.

UTILITY REGULATION

FEDERAL REGULATION

Other EPACT provisions included tax changes for the utility industry; incentives for emissions reductions; federal insurance and incentives to build new nuclear power plants; and certain protection for native retail load customers of load-serving entities. EPACT gave the FERC "backstop" transmission siting authority which provides for federal intervention, subject to limitations, when states are unable or unwilling to resolve transmission issues. EPACT also provided incentives and funding for clean coal technologies, provided initiatives to voluntarily reduce greenhouse gases and redesignated the Code's Section 29 (Section 29) tax credit as a general business credit under the Code's Section 45K (Section 45K). In addition, the law requires both the FERC and the U.S. Department of Energy (DOE) to study how utilities dispatch their resources to meet the needs of their customers. The results of these studies or any related actions taken by the DOE could impact the Utilities' system operations.

The FERC has adopted final rules implementing much of its new authority under EPACT. These new rules require the FERC's approval prior to any merger involving a public utility; require the FERC's approval prior to the disposition of any utility asset with a market value in excess of $10 million; prohibit market participants from intentionally or recklessly making any fraudulent or misleading statements with regard to transactions subject to the FERC's jurisdiction; and provides the procedures and rules for the establishment of an electric reliability organization (ERO) that will propose and enforce mandatory reliability standards for the bulk power electric system.

On July 20, 2006, the FERC certified the North American Electric Reliability Council (NERC) as the ERO. In addition, on October 20, 2006, the FERC issued a Notice of Proposed Rulemaking (NOPR) on reliability standards originally proposed by the NERC, which would transition compliance with these standards from voluntary to mandatory. The proposed reliability standards were based on the current NERC reliability standards. The FERC proposes to approve 83 reliability standards, as currently written, and make compliance mandatory. After these standards are approved, the FERC has directed the NERC to make technical improvements to 62 of the 83 standards. An additional 24 standards proposed by the NERC that were not adopted remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. Mandatory reliability standards are expected to be in place by the summer of 2007. All users, owners and operators of the bulk power system, including PEC and PEF, will be subject to these standards upon their approval by the FERC.

Recent reliability audits of PEC operations have not resulted in any standards violations. PEF is in the process of executing a mitigation plan associated with findings from a 2004 reliability audit. Based on the direction the FERC has given to the NERC to make revisions to 62 of the standards proposed for adoption, we expect standards to migrate to stricter requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, failure to comply with the reliability standards approved by the FERC could result in the imposition of fines and civil penalties.

On January 18, 2007, the FERC issued a NOPR regarding Standards of Conduct in response to a 2006 court case, which invalidated certain portions of the Standards of Conduct as they relate to natural gas companies. The NOPR requests comment with respect to whether the electric Standards of Conduct should be limited to marketing affiliates and proposes to create two new categories of shared employees: one for employees involved in resource competitive solicitations and the other for employees involved in integrated resource planning. We cannot predict the outcome of this matter.

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

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

STATE REGULATION

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

Retail Rate Matters

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

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

During 2005, the FPSC approved a four-year base rate agreement with PEF. The new base rates took effect the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009 with PEF having the sole option to extend the agreement through the last billing cycle of June 2010. Base rates will be adjusted in late 2007 depending on the in-service date of specified generation facilities. PEF's base rate settlement also provides for revenue sharing between PEF and its ratepayers. For 2006, PEF agreed to refund two-thirds of retail base revenues between the $1.499 billion threshold and the $1.549 billion cap and 100 percent of revenues above the $1.549 billion cap. However, PEF's 2006 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. Both the threshold and cap will be adjusted annually for rolling average 10-year retail kilowatt-hour (kWh) sales growth.

Retail Cost-recovery Clauses

Each of the Utilities' state utility commissions allows recovery of certain costs through various cost-recovery clauses, to the extent the respective commission determines in an annual hearing that such costs are prudent. Each state utility commission's determination results in the addition of a rider to a utility's base rates to reflect the approval of these costs and to reflect any past over- or under-recovery of costs. The Utilities do not earn a return on the recovery of eligible operating expenses under such clauses; however, the FPSC has authorized PEF to earn a return for specified capital investments for environmental compliance and utility plant. Fuel and certain purchased power costs are eligible for recovery by the Utilities. The Utilities use coal, oil, hydroelectric (PEC only), natural gas and nuclear power to generate electricity thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the regulatory treatment of these costs and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of the Utilities, unless a commission finds a portion of such costs to have been imprudently incurred. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the cash flow of the Utilities. See MD&A – "Regulatory Matters and Recovery of Costs" for additional discussion regarding cost-recovery clauses.

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

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

Storm Recovery

In accordance with its base rate agreement, PEF accrues $6 million annually in base rates to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance (O&M) expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions.

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

During 2006, PEF entered into, and the FPSC approved, a settlement agreement with certain intervenors in its storm cost-recovery docket. The settlement agreement, as amended, allows PEF to extend its current two-year storm surcharge for an additional 12-month period. The extension, which begins August 2007, will replenish the existing storm reserve by an estimated additional $130 million. The amended settlement agreement provides that in the event future storms cause the reserve to be depleted, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

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

See Note 7 for further discussion of regulatory matters.

NUCLEAR MATTERS

GENERAL

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

PEC owns and operates four nuclear generating units, Brunswick Nuclear Plant (Brunswick) Unit No. 1 and Unit No. 2, Shearon Harris Nuclear Plant (Harris), and Robinson Nuclear Plant (Robinson). NRC operating licenses, including license extensions granted through 2006, for Brunswick No. 1 and No. 2, Harris and Robinson currently expire in September 2036, December 2034, October 2026 and July 2030, respectively. On June 26, 2006, Brunswick received 20-year extensions from the NRC on the operating licenses for its two nuclear reactors. On November 14, 2006, we submitted an application to the NRC requesting a 20-year extension of the Harris operating license.

PEF owns and operates one nuclear generating unit, Crystal River Unit No. 3 (CR3). The NRC operating license for CR3 currently expires in December 2016. We expect to submit an application to extend this license 20 years in the first quarter of 2009.

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

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

Since 2002, the NRC has issued various bulletins and orders addressing inspection activities associated with pressurized water reactor vessels. We have complied with all requests. Additionally, we replaced the reactor vessel head at CR3 in 2003 and at Robinson in 2005.

POTENTIAL NEW CONSTRUCTION

We have announced that we are pursuing development of combined license (COL) applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a plant or plants. On January 23, 2006, we announced that PEC selected the Harris site to evaluate for possible future nuclear expansion. We currently expect to file the application for the COL for PEC's Harris site in 2007. We have selected the Westinghouse Electric AP-1000 reactor design as the technology upon which to base PEC's potential application submission. On December 12, 2006, we announced that PEF selected a site in Levy County, Fla. to evaluate for possible future nuclear expansion and PEF expects to file the application for the COL in 2008. We have not selected the reactor design technology upon which to base PEF's potential application submission. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, construction activities could begin as early as 2010, and new plants could be online in late 2016. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

SECURITY

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

SPENT FUEL AND OTHER HIGH-LEVEL RADIOACTIVE WASTE

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

With certain modifications and additional approvals by the NRC, including the installation of onsite dry cask storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license extensions, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pool through the expiration of its operating license, including any license extensions.

On January 16, 2007, the U.S. Supreme Court declined to hear an appeal of a Ninth Circuit U.S. Court of Appeals' decision in which the Ninth Circuit held that the NRC is required to consider the environmental impacts of terrorist attacks under the National Environmental Policy Act in authorizing an independent spent fuel storage installation. Similar cases, including cases involving operating license renewals, are pending in seven other jurisdictions. The NRC is considering the scope and import of the Ninth Circuit's decision in reviewing its operating license renewal program. The extent and timing of the NRC's application of the case is unclear at this time, and the impact, if any, on PEC's pending Harris operating license renewal application or any future PEC or PEF operating licensing proceedings cannot be predicted at this time.

Since 2001, PEC and PEF have made various modifications to increase the output of their nuclear facilities. To date, the cumulative increase is approximately 315 MW, of which 311 MW is at PEC and 4 MW is at PEF. In January 2007, the FPSC approved PEF's petition to uprate CR3's gross output by approximately 180 MW (See Note 7C).

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

DECOMMISSIONING

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

ENVIRONMENTAL

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

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

There are presently several sites, including 10 manufactured gas plant (MGP) sites, with respect to which we have been notified by the EPA, the State of North Carolina or the State of Florida of our potential liability, as a potentially responsible party (PRP). We have accrued costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. While we accrue for probable costs that can be reasonably estimated, based upon the current status of some sites, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

See Note 21 and MD&A – "Other Matters – Environmental Matters" for additional discussion of our environmental matters, which identifies specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

As of February 15, 2007, we employed approximately 11,000 full-time employees. Of this total, approximately 2,000 employees at PEF are represented by the International Brotherhood of Electrical Workers (IBEW). The three-year labor contract with the IBEW expires in November 2008. We consider our relationship with employees, including those covered by collective bargaining agreements, to be good.

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

As of February 15, 2007, PEC and PEF employed approximately 5,000 and 4,000 full-time employees, respectively.

ELECTRIC – PEC

GENERAL

PEC is a regulated public utility formed under the laws of North Carolina in 1926 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2006, PEC had a total summer generating capacity (including jointly owned capacity) of 12,409 MW. For additional information about PEC's generating plants, see "Electric – PEC" in Item 2, "Properties." PEC's system normally experiences its highest peak demands during the summer, and the all-time system peak of 12,577 megawatt-hour (MWh) was set on July 27, 2005.

PEC distributes and sells electricity in North Carolina and northeastern South Carolina. The service territory covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. At December 31, 2006, PEC was providing electric services, retail and wholesale, to approximately 1.4 million customers. Major wholesale power sales customers include North Carolina Eastern Municipal Power Agency (Power Agency), North Carolina Electric Membership Corporation and Public Works Commission of the City of Fayetteville, North Carolina (PWC). PEC is subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the NRC. No single customer accounts for more than 10 percent of PEC's revenues.

BILLED ELECTRIC REVENUES

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

BILLED ELECTRIC REVENUE PERCENTAGES

	2006	2005	2004
Residential	**37%**	37%	38%
Commercial	**25%**	24%	25%
Industrial	**18%**	18%	19%
Wholesale	**18%**	19%	16%
Other retail	**2%**	2%	2%

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

FUEL AND PURCHASED POWER

SOURCES OF GENERATION

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

ENERGY MIX PERCENTAGES

	2006	2005	2004
Coal	**47%**	47%	47%
Nuclear	**43%**	42%	43%
Purchased power	**6%**	6%	6%
Oil/Gas	**3%**	4%	3%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and certain purchased power costs to its customers through fuel adjustment clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, "Quantitative And Qualitative Disclosures About Market Risk" and Item 1A, "Risk Factors." However, PEC believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

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

AVERAGE FUEL COST

(per million Btu)	**2006**	2005	2004
Coal	**$2.90**	$2.72	$2.17
Nuclear	**0.43**	0.42	0.42
Oil	**11.04**	8.60	6.78
Gas	**9.87**	10.90	8.29
Weighted-average	**2.06**	2.03	1.57

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

Coal

PEC anticipates a requirement of approximately 13 million tons of coal in 2007. Almost all of the coal will be supplied from Appalachian coal sources in the United States and will be primarily delivered by rail.

For 2007, PEC has short-term, intermediate and long-term agreements from various sources for approximately 99 percent of its estimated burn requirements of its coal units. The contracts have expiration dates ranging from one to five years. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

Nuclear

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

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

Oil and Gas

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from several suppliers. PEC has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEC's oil and gas is hedged at a fixed price or determined by market prices as reported in certain industry publications. PEC believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEC's natural gas transportation for its baseload gas generation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity under other contracts and utilizes interruptible transportation for its peaking load requirements.

Hydroelectric

PEC has three hydroelectric generating plants licensed by the FERC: Walters, Tillery and Blewett. PEC also owns the Marshall Plant, which has a license exemption. The total maximum dependable capacity for all four units is 225 MW. PEC submitted an application to relicense for 50 years its Tillery and Blewett Plants. The remaining phase of the application process is expected to take up to one year. The license for these plants currently expires in April 2008. The Walters Plant license will expire in 2034.

Purchased Power

PEC purchased approximately 4.2 million MWh, 4.7 million MWh and 4.0 million MWh of its system energy requirements during 2006, 2005 and 2004 and had 1,461 MW of firm purchased capacity under contract during 2006. PEC may acquire additional purchased power capacity in the future to accommodate a portion of its system load needs, and PEC believes that it can obtain enough purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

ELECTRIC – PEF

GENERAL

PEF, incorporated in Florida in 1899, is an operating public utility engaged in the generation, transmission, distribution and sale of electricity. At December 31, 2006, PEF had a total summer generating capacity (including jointly owned capacity) of 8,913 MW. For additional information about PEF's generating plants, see "Electric – PEF" in Item 2, "Properties." PEF's system normally experiences its highest peak demands during the winter, and the all-time system peak of 10,131 MWh was set on January 24, 2003.

PEF distributes and sells electricity in Florida. The service territory covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. At December 31, 2006, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Reedy Creek Improvement District, Tampa Electric Company, and the cities of Bartow and Winter Park. PEF is subject to the rules and regulations of the FERC, the FPSC and the NRC. No single customer accounts for more than 10 percent of PEF's revenues.

BILLED ELECTRIC REVENUES

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

BILLED ELECTRIC REVENUE PERCENTAGES

	2006	2005	2004
Residential	**53%**	52%	53%
Commercial	**26%**	25%	25%
Industrial	**8%**	8%	8%
Wholesale	**7%**	9%	8%
Other retail	**6%**	6%	6%

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

FUEL AND PURCHASED POWER

SOURCES OF GENERATION

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

ENERGY MIX PERCENTAGES

	2006	2005	2004
Coal [(a)]	**32%**	33%	32%
Oil/Gas	**31%**	33%	32%
Nuclear	**15%**	13%	16%
Purchased Power	**22%**	21%	20%

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

PEF is generally permitted to pass the cost of fuel and purchased power to its customers through fuel adjustment clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, "Quantitative And Qualitative Disclosures About Market Risk" and Item 1A, "Risk Factors." However, PEF believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

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

AVERAGE FUEL COST

(per million Btu)	**2006**	2005	2004
Coal [(a)]	**$3.16**	$2.70	$2.30
Oil	**7.03**	5.90	4.67
Nuclear	**0.50**	0.51	0.49
Gas	**7.41**	8.53	6.41
Weighted-average	**4.21**	4.15	3.21

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

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

Coal

PEF anticipates a combined requirement of approximately 6 million tons of coal in 2007. Approximately 60 percent of the coal is expected to be supplied from Appalachian coal sources in the United States and 40 percent supplied from coal sources in South America. Approximately 55 percent of the coal is expected to be delivered by rail and the remainder by water. Prior to 2006, coal for PEF was supplied by Progress Fuels, a subsidiary of Progress Energy, pursuant to contracts between PEF and Progress Fuels. Beginning in 2006, PEF began entering into coal contracts on its own behalf.

For 2007, PEF has medium-term and long-term contracts with various sources for approximately 99 percent of the estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to four years. All the coal to be purchased for PEF is considered to be low-sulfur coal by industry standards.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from several suppliers. PEF has dual-fuel generating facilities that can operate with both oil and gas. PEF's oil and gas is either hedged at a fixed price or determined by market prices as reported in certain industry publications. PEF believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEF's natural gas transportation for its gas generation is purchased under term firm transportation contracts with interstate pipelines. PEF purchases capacity on a seasonal basis from numerous shippers and interstate pipelines and utilizes interruptible transportation to serve its peaking load requirements.

Nuclear

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

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

Purchased Power

PEF purchased approximately 10.4 million MWh, 9.9 million MWh and 9.4 million MWh of its system energy requirements during 2006, 2005 and 2004 respectively, and had 2,073 MW of firm purchased capacity under contract during 2006. These agreements include approximately 943 MW of capacity under contract with certain QFs. PEF may acquire additional purchased power capacity in the future to accommodate a portion of its system load needs, and PEF believes that it can obtain enough purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

COAL AND SYNTHETIC FUELS

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels. Our synthetic fuels facilities include five majority-owned synthetic fuels entities and one minority interest in a synthetic fuels entity and have the capability to produce 19 million tons per year. The production and sale of these products qualifies for federal income tax credits within the meaning of Section 29/45K so long as certain requirements are satisfied. Qualifying synthetic fuels facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year may be phased out if annual average market prices for crude oil exceed certain prices. Synthetic fuels are generally not economical to produce and sell absent the credits. Through tax year 2005, our ability to utilize tax credits was dependent on having a sufficient tax liability. In 2005, the tax law was changed and this constraint no longer applies beginning in tax year 2006. The tax credit program for the production of qualifying synthetic fuels is scheduled to expire at the end of 2007.

In May 2006, we idled production of synthetic fuels at our synthetic fuels facilities due to the high level of oil prices. Based on significantly reduced oil prices combined with favorable oil price projections, we resumed limited production at our synthetic fuels facilities in September and October 2006, which continued through the end of 2006. For the year ended December 31, 2006, we produced approximately 3.7 million tons of synthetic fuels.

We also have five terminals on the Ohio River and its tributaries which blend and transload coal and are part of the trucking, rail and barge network for coal delivery; these terminals also support our synthetic fuel facilities.

Our coal and synthetic fuels operations and related risks are described in more detail in Item 1A, "Risk Factors" and MD&A - "Other Matters – Synthetic Fuels Tax Credits."

CORPORATE AND OTHER

GENERAL

The Corporate and Other segment is comprised of nonregulated business areas that do not separately meet the disclosure requirements as a business segment. It primarily includes the activities of the Parent and PESC as well as miscellaneous nonregulated businesses. PESC provides centralized administrative, management and support services to our subsidiaries. See Note 18 for additional information about PESC services provided and costs allocated to subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2006	2005	2004	2003	2002
Energy supply (millions of kWhs)					
Generated					
Steam	**48,770**	52,306	50,782	51,501	49,734
Nuclear	**30,602**	30,120	30,445	30,576	30,126
Combustion Turbines/Combined Cycle	**11,857**	11,349	9,695	7,819	8,522
Hydro	**594**	749	802	955	491
Purchased	**14,664**	14,566	13,466	13,848	14,305
Total energy supply (Company share)	**106,487**	109,090	105,190	104,699	103,178
Jointly owned share [(a)]	**5,224**	5,388	5,395	5,213	5,258
Total system energy supply	**111,711**	114,478	110,585	109,912	108,436
Average fuel cost (per million Btu)					
Fossil	**$4.17**	$4.05	$3.17	$2.94	$2.62
Nuclear fuel	**$0.44**	$0.44	$0.44	$0.44	$0.44
All fuels	**$2.86**	$2.83	$2.21	$2.05	$1.84
Energy sales (millions of kWhs)					
Retail					
Residential	**36,280**	36,558	35,350	34,712	33,993
Commercial	**25,333**	25,258	24,753	24,110	23,888
Industrial	**16,553**	16,856	17,105	16,749	16,924
Other Retail	**4,695**	4,608	4,475	4,382	4,287
Wholesale	**19,117**	21,137	18,323	19,841	19,204
Unbilled	**(371)**	(440)	449	189	275
Total energy sales	**101,607**	103,977	100,455	99,983	98,571
Company uses and losses	**4,880**	5,113	4,735	4,716	4,607
Total energy requirements	**106,487**	109,090	105,190	104,699	103,178
Electric revenues (in millions)					
Retail	**$7,429**	$6,607	$6,066	$5,620	$5,515
Wholesale	**1,039**	1,103	843	914	881
Miscellaneous revenue	**254**	235	244	207	205
Total electric revenues	**$8,722**	$7,945	$7,153	$6,741	$6,601

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

REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2006	2005	2004	2003	2002
Energy supply (millions of kWhs)					
Generated					
Steam	**28,985**	29,780	28,632	28,522	28,547
Nuclear	**24,220**	24,291	23,742	24,537	23,425
Combustion Turbines/Combined Cycle	**2,106**	2,475	1,926	1,344	1,934
Hydro	**594**	749	802	955	491
Purchased	**4,229**	4,656	4,023	4,467	5,213
Total energy supply (Company share)	**60,134**	61,951	59,125	59,825	59,610
Jointly owned share [a]	**4,649**	4,857	4,794	4,670	4,659
Total system energy supply	**64,783**	66,808	63,919	64,495	64,269
Average fuel cost (per million Btu)					
Fossil	**$3.37**	$3.30	$2.52	$2.29	$2.16
Nuclear fuel	**$0.43**	$0.42	$0.42	$0.43	$0.43
All fuels	**$2.06**	$2.03	$1.57	$1.43	$1.38
Energy sales (millions of kWhs)					
Retail					
Residential	**16,259**	16,664	16,003	15,283	15,239
Commercial	**13,358**	13,313	13,019	12,557	12,468
Industrial	**12,393**	12,716	13,036	12,749	13,089
Other Retail	**1,419**	1,410	1,431	1,408	1,437
Wholesale	**14,584**	15,673	13,222	15,518	15,024
Unbilled	**(137)**	(235)	91	(44)	270
Total energy sales	**57,876**	59,541	56,802	57,471	57,527
Company uses and losses	**2,258**	2,410	2,323	2,354	2,083
Total energy requirements	**60,134**	61,951	59,125	59,825	59,610
Electric revenues (in millions)					
Retail	**$3,268**	$3,133	$2,953	$2,824	$2,796
Wholesale	**720**	759	575	687	651
Miscellaneous revenue	**97**	98	100	78	92
Total electric revenues	**$4,085**	$3,990	$3,628	$3,589	$3,539

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

REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2006	2005	2004	2003	2004
Energy supply (millions of kWhs)					
Generated					
Steam	**19,785**	22,526	22,150	22,979	21,187
Nuclear	**6,382**	5,829	6,703	6,039	6,701
Combustion Turbines/Combined Cycle	**9,751**	8,874	7,769	6,475	6,588
Purchased	**10,435**	9,910	9,443	9,381	9,092
Total energy supply (Company share)	**46,353**	47,139	46,065	44,874	43,568
Jointly owned share [(a)]	**575**	531	601	543	599
Total system energy supply	**46,928**	47,670	46,666	45,417	44,167
Average fuel cost (per million Btu)					
Fossil	**$5.09**	$4.88	$3.86	$3.63	$3.15
Nuclear fuel	**$0.50**	$0.51	$0.49	$0.50	$0.46
All fuels	**$4.21**	$4.15	$3.21	$3.07	$2.60
Energy sales (millions of kWhs)					
Retail					
Residential	**20,021**	19,894	19,347	19,429	18,754
Commercial	**11,975**	11,945	11,734	11,553	11,420
Industrial	**4,160**	4,140	4,069	4,000	3,835
Other Retail	**3,276**	3,198	3,044	2,974	2,850
Wholesale	**4,533**	5,464	5,101	4,323	4,180
Unbilled	**(234)**	(205)	358	233	5
Total energy sales	**43,731**	44,436	43,653	42,512	41,044
Company uses and losses	**2,622**	2,703	2,412	2,362	2,524
Total energy requirements	**46,353**	47,139	46,065	44,874	43,568
Electric revenues (in millions)					
Retail	**$4,161**	$3,474	$3,113	$2,796	$2,719
Wholesale	**319**	344	268	227	230
Miscellaneous revenue	**159**	137	144	129	113
Total electric revenues	**$4,639**	$3,955	$3,525	$3,152	$3,062

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

ITEM 1A. RISK FACTORS

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

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

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

We are subject to comprehensive regulation by multiple federal, state and local regulatory agencies, which significantly influences our operating environment and may affect our ability to recover costs from utility customers. We are subject to regulatory oversight with respect to, among other things, rates and service for electric energy sold at retail, retail service territory, siting and construction of facilities, and issuances of securities. In addition, the Utilities are subject to federal regulation with respect to transmission and sales of wholesale power, accounting and certain other matters. We are also required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. Laws and regulations frequently change and the ultimate costs of compliance cannot be precisely estimated. Such changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and which may impact or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste, and hazardous waste production, handling and disposal. These laws and regulations can result in increased capital, operating and other costs, particularly with regard to enforcement efforts focused on existing power plants and compliance plans with regard to new power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable regulations might result in the imposition of fines and penalties by regulatory authorities. We cannot provide assurance that existing environmental regulations will not be revised or that new environmental regulations will not be adopted or become applicable to us. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from our ratepayers.

In addition, we may be deemed a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs. We have been identified as a PRP at 10 former MGP sites (eight at PEC and two at PEF). We are also currently in the process of assessing potential costs and exposures at the Ward Transformer site, Carolina Transformer site and other sites. Both PEC and PEF evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. No material claims are currently pending. While we accrue for probable costs that can be reasonably estimated, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

There are proposals and ongoing studies at the state and federal levels to address global climate change that would regulate carbon dioxide (CO_2) and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to our operations. We have articulated principles that we believe should be incorporated into any global climate change policy. In 2005, we initiated a study to assess the impact of constraints on CO_2 and other air emissions. On March 27, 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time.

Our compliance with environmental regulations requires significant capital expenditures that impact our financial condition. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Clean air regulations require reduction of emissions of NOx, SO_2 and mercury from coal-fired power plants. We expect that future capital expenditures required to meet the emission limits could be in excess of $1.0 billion each at PEC and PEF, respectively, through 2018, which corresponds to the latest emission reduction deadline. However, these costs could be higher than currently expected and have an adverse impact on our results of operations and financial condition.

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

See Note 21 for additional discussion of environmental matters.

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

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

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

Our ability to recover significant costs resulting from severe weather events is subject to regulatory oversight and the timing and amount of any such recovery is uncertain and may impact our financial conditions.

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

Under a regulatory order, PEF maintains a storm damage reserve account for major storms. Due to the significant costs incurred to recover from the damage sustained during the 2004 hurricane season, PEF's storm damage reserve accounts were largely depleted at December 31, 2005. During 2006, the FPSC approved a modified settlement agreement that extends PEF's current two-year storm surcharge for retail ratepayers for an additional 12-month period ending in August 2008. The extension is expected to replenish PEF's storm reserve by an estimated additional $130 million. In the event future storms cause the reserve to be depleted, the modified settlement agreement provides for PEF to petition the FPSC for implementation of an interim retail surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors to the settlement agreement agreed not to oppose recovery of 80 percent of a future claimed deficiency but reserved the right to challenge the recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. Storm reserve costs attributable to wholesale customers may be amortized consistent with recovery of such amounts in wholesale rates, albeit at a specified amount per year resulting in an extended recovery period.

PEC does not maintain a storm damage reserve account and does not have an ongoing regulatory mechanism to recover storm costs. PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over five-year periods. PEC did not seek deferral of storm costs from the NCUC or SCPSC during 2006 or 2005.

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

The Utilities are impacted by the economic cycles of the customers we serve. For the year ended December 31, 2006, commercial and industrial customers represented approximately 43 percent and 34 percent of PEC's and PEF's billed electric revenues, respectively. Consequently, if our commercial and industrial customers experience economic downturns, their consumption of electricity may drop and our revenues can be negatively impacted. In recent years, in North Carolina and South Carolina, sales to industrial customers have been affected by downturns in the textile and chemical industries.

For the year ended December 31, 2006, 18 percent and seven percent of PEC's and PEF's billed electric revenues, respectively, were from wholesale sales. Wholesale revenues fluctuate with regional demand, fuel prices and contracted capacity. Our wholesale profitability is dependent upon our ability to renew or replace expiring wholesale contracts on favorable terms and market conditions.

In 2004, the FERC issued orders concerning utilities' ability to sell wholesale electricity at market-based rates, including the adoption of two interim screens for assessing an applicant's potential generation market power for determining whether the applicant should be allowed to sell wholesale electricity at market-based rates. The Utilities do not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, PEC filed revisions to its market-based rate tariffs restricting PEC to sales outside of PEC's control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs. We do not anticipate that the operations of the Utilities will be materially impacted by these market-based rates decisions.

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

Increased competition resulting from deregulation or restructuring efforts or from industry consolidation could have a significant adverse financial impact on us and consequently, on our results of operations and cash flows. Retail competition and the unbundling of regulated energy service could have a significant adverse financial impact on us due to lower electric operating revenues, potential impairment of generation assets, loss of retail customers, or increased costs of capital. Because we have not previously operated in a competitive retail environment, we cannot predict the extent to which additional competitors would enter the market or the timing of such entry. To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot predict when or if we will be subject to changes in legislation or regulation nor can we predict the impact of these changes on our financial condition, results of operations or cash flows.

Increased commodity prices may adversely affect various aspects of the Utilities' operations as well as the Utilities' financial condition, results of operations or cash flows.

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related commodities as a result of our ownership of energy-related assets. We have hedging strategies in place to mitigate negative 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. While the Utilities' state utility commissions allow recovery of certain of these costs through various cost-recovery clauses, there is the potential that a portion of these future costs could be deemed imprudent by the Utilities' respective commissions. There is also a delay between the timing of when such costs are incurred and when the costs are recovered from the ratepayers. This lag can adversely impact the cash flow of the Utilities and, consequently, our interest expense.

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

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

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

Prices for SO_2 emission allowance credits under the EPA's emission trading program increased significantly during 2005 and then significantly declined by the end of 2006. While SO_2 allowances are eligible for annual recovery in PEF's jurisdictions in Florida and PEC's in South Carolina, no such annual recovery exists in North Carolina for PEC. Future increases in the price of SO_2 allowances could have a significant adverse financial impact on us and PEC and consequently, on our results of operations and cash flows.

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

The Parent is a holding company and as such, has no revenue-generating operations of its own. The Parent's ability to meet its financial obligations associated with the debt service obligations on \$2.6 billion of holding company debt and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily the Utilities, and the ability of its subsidiaries to pay upstream dividends or to repay funds due the Parent. Prior to funding the Parent, its subsidiaries have financial obligations that must be satisfied, including among others, their respective debt service, preferred dividends and obligations to trade creditors. Should the Utilities not be able to pay dividends or repay funds due to the Parent, the Parent's ability to pay interest and dividends would be restricted.

Divesting of nonregulated subsidiaries may take longer than expected, may result in unexpected additional charges and may not yield the benefits that we expect.

Consistent with our announced intention to reduce holding company debt and business risk, we have divested of a number of nonregulated businesses. Certain of our divestitures announced in 2006 are expected to close during 2007. We have recognized known or estimated expenses related to these divestitures but future additional charges may be recognized depending on changes in market conditions, the transfer of existing contracts and ultimate settlement of carryover liabilities, among other factors. Such charges for the CCO divestiture could exceed $200 million. In addition, completion of these anticipated divestitures may take significantly longer than expected, thus increasing our costs and delaying our ability to benefit from such divestitures.

The rates that PEC and PEF may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins could be adversely affected if we do not control costs.

The NCUC, the SCPSC and the FPSC each exercises regulatory authority for review and approval of the retail electric power rates charged within its respective state. With the Utilities' expected increased expenditures for environmental compliance, baseload generation and higher commodity prices, we anticipate that the Utilities' operations will be subject to an even higher level of scrutiny from regulators, policymakers and ratepayers. State regulators may not allow PEC and PEF to increase retail rates in the manner or to the extent requested. State regulators may also seek to reduce or freeze retail rates.

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

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, regulatory, terrorism, and financial risks, that could result in fines or the shutdown of our nuclear units, which may present potential exposures in excess of our insurance coverage.

PEC (four units; 3,485 MW) and PEF (one unit; 838 MW) own and operate five nuclear units that collectively represented approximately 4,323 MW, or 20 percent, of our regulated generation capacity for the year ended December 31, 2006. In addition, we are exploring the possibility of expanding our nuclear generating capacity with two additional units at both PEC and PEF to meet future expected baseload generation needs. Our nuclear facilities are subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate capital reserves for decommissioning, limitations on amounts and types of insurance available, potential operational liabilities, and the costs of securing the facilities against possible terrorist attacks. We maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks. However, damages from an accident or business interruption at our nuclear units could exceed the amount of our insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require us to make substantial capital expenditures at our nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

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

Meeting the anticipated growth in our service territories may require, among other things, the construction within the next decade of new coal and/or nuclear generation facilities to increase our baseload generation 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, any of which could adversely impact our financial condition, cash flows or results of operations.

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (i) increasing energy efficiency and investing in the development of new energy resources for the future; (ii) modernizing existing plants to produce energy more efficiently using state-of-the-art technology; and (iii) investing in new generating plants and associated transmission facilities. The risks of each of these elements are discussed below:

Energy Efficiency and New Energy Resources

We are actively pursuing expansion of our energy efficiency and conservation programs through residential energy inspections, demand side management programs and providing energy conservation tips to our customers. We are subject to the risk that our customers may not participate in our conservation programs or the forecasted results from these programs may be less than anticipated requiring us to further expand our baseload generation or purchase additional power.

Current proposals at the state and federal levels for renewable energy standards could require the Utilities to produce or buy a portion of their energy from renewable energy sources. Mandated standards could result in the use of renewable fuels that are not cost-effective in order to comply with requirements to have renewable energy be a specified percentage of the Utilities' energy mix. Currently, we partner with organizations throughout our service territories to support hydrogen, solar and other forms of renewable and alternative energy. We have invested in research for alternative energy sources that might subsequently be determined to not be cost-efficient or cost-effective, thus subjecting us to the risks of further expanding our baseload generation or purchasing additional power on the open market at then-prevailing prices.

Modernization and Construction of Generating Plants

We are currently evaluating our options for new generating plants, including coal and nuclear technologies. At this time, no definitive decision has been made regarding the construction of either coal or nuclear plants, or both. If we decide to construct new generation facilities or expand or modernize existing facilities, there is no assurance that we will be able to successfully and timely complete the projects within our projected budgets. These projects are long-term and potentially would be subject to significant cost increases for labor and materials. Should any such construction, expansion or modernization efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement. Furthermore, we have no assurance that costs incurred to construct, expand or modernize generation and associated transmission facilities will be recoverable through our base rates.

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

- power market conditions;
- competing fuel prices and fuel diversity;
- the regulatory environment;
- time required to permit and construct;
- environmental impact;
- both public and policymaker support;
- siting and construction of transmission facilities;
- cost and availability of construction materials and labor; and

- the ability to obtain financing on favorable terms.

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

Coal

In addition to the risks discussed above, the construction of a coal-fired power plant requires a number of conditions to be successful. These include, but are not limited to, consideration of emissions of NOx, SO_2 and mercury; an efficient licensing process; disposal of coal byproducts such as slag and fly ash; and anticipated regulation of carbon.

As discussed earlier, air pollution control equipment requires the use of significant amounts of ammonia and limestone which may be in high demand and have a resulting higher purchase price.

Nuclear

In addition to the risks discussed above, the successful construction of a new nuclear power plant requires 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 licensing process, and a viable program for managing spent nuclear fuel. We cannot provide certainty that these conditions will exist.

We have announced that we are pursuing development of COL applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a potential plant or plants. We have selected a site in North Carolina and a site in Florida to evaluate for possible future nuclear expansion. We currently expect to file the application for the COL for PEC's site in 2007 and PEF's site in 2008. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, construction activities could begin as early as 2010, and new plants could be online in late 2016. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

EPACT provides for an annual tax credit of 1.8 cents/kWh for nuclear facilities for the first eight years of operation. However, the credit is limited to the first 6,000 MW of new nuclear generation in the United States that have met the permitting, construction and placed-in-service milestones specified by EPACT and has an annual cap of $125 million per unit. The credit allocation process among new nuclear plants has not been determined. Other utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant constructed by us would qualify for these additional incentives. Failure to qualify for these incentives could significantly impact the economics of building a nuclear facility.

In addition, other COL applicants would be pursuing regulatory approval, financing 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.

Under rules recently issued by the FPSC, Florida utilities will be allowed to recover prudently incurred siting, preconstruction costs and allowance for funds used during construction (AFUDC) on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility.

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

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

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

- operator error and breakdown or failure of equipment or processes;
- operational limitations imposed by environmental or other regulatory requirements;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes;
- interruptions of fuel supply;
- compliance with mandatory reliability standards for the bulk power electric system when such standards are adopted and as subsequently revised; and
- catastrophic events such as hurricanes, floods, earthquakes, fires, explosions, terrorist attacks, pandemic health events such as avian influenza or other similar occurrences.

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

We anticipate that mandatory reliability standards will be in place by the summer of 2007. We expect these standards will become stricter over time. The financial impact of mandatory compliance cannot currently be determined. If we are unable to meet the reliability standards for the bulk power electric system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, failure to comply with the reliability standards could result in the imposition of fines and penalties.

A decrease in operational performance from the Utilities' generating facilities and delivery systems or an increase in the cost of operating the facilities could have an adverse effect on our business and results of operations.

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

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

Increases in our leverage could adversely affect our competitive position, business planning and flexibility, financial condition, ability to service our debt obligations and to pay dividends on our common stock, and ability to access capital on favorable terms.

As discussed above, we rely heavily on our commercial paper and long-term debt. At December 31, 2006, we had no commercial paper outstanding or other short-term borrowings and our long-term debt balances were as follows:

(in millions)	Total Long-Term Debt, Net
Progress Energy, unconsolidated [(a)]	$2,581
PEC	3,470
PEF	2,468
Other subsidiaries [(b)]	316
Progress Energy, consolidated [(c)]	$8,835

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

(b) Includes the following subsidiaries: Florida Progress Funding Corporation ($271 million) and Progress Capital Holdings, Inc. ($45 million).

(c) Net of current portion, which at December 31, 2006, was $324 million on a consolidated basis.

At December 31, 2006, we had an aggregate of three committed revolving credit agreements (RCAs) that supported our commercial paper programs totaling $2.030 billion. Our internal financial policy precludes us from issuing commercial paper in excess of our revolving credit lines. At December 31, 2006, we had no outstanding borrowings under our credit facilities and had a total amount of $60 million of letters of credit issued, leaving an additional $1.970 billion available for future borrowing under our revolving credit lines.

Our revolving credit lines impose various limitations that could impact our liquidity, such as defined maximum total debt to total capital (leverage) ratios. Under these revolving credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on the Consolidated Balance Sheets. At December 31, 2006, the required and actual ratios, pursuant to the terms of the credit agreements were as follows:

	Leverage Ratios	
	Maximum Ratio	Actual Ratio [(a)]
Progress Energy, Inc.	68%	55.4%
PEC	65%	52.3%
PEF	65%	49.4%

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets.

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

Additionally, certain of Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $2.6 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

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

In the event our leverage increases such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs. Additionally, a significant increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- impacting our ability to pay dividends on our common stock at the current rate;
- making it more difficult for us to satisfy our existing financial obligations;
- limiting our ability to obtain additional financing, if needed, for working capital, acquisitions, debt service requirements or other purposes;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to debt repayment thereby reducing funds available for operations, future business opportunities or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete;
- placing us at a competitive disadvantage compared to competitors who have less debt; and
- causing a downgrade in our credit ratings.

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

Any reduction in our credit ratings below investment grade would likely increase our borrowing costs, limit our access to additional capital and require posting of collateral, all of which could materially and adversely affect our business, results of operations and financial condition.

While the long-term target credit ratings for the Parent and the Utilities are above the minimum investment grade rating, we cannot provide certainty that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Unlike the contracts described below, our debt indentures and credit agreements do not contain any "ratings triggers," which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. Any downgrade could increase our borrowing costs and may adversely affect our access to capital, which could negatively impact our financial results and business plans. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities or those of PEC or PEF and that each agency's rating should be evaluated independently of any other agency's rating.

As a part of normal business, we enter into various agreements that provide future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, we have issued $1.489 billion of guarantees for future financial or performance assurance. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

The majority of contracts supported by the guarantees contain provisions that trigger guarantee obligations based on downgrade events to below investment grade (below Baa3 or BBB-) by Moody's Investors Service, Inc. (Moody's) or Standard & Poor's Rating Services (S&P) for the Parent's senior unsecured debt rating, ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. At December 31, 2006, the Parent's senior unsecured debt rating was Baa2 by Moody's and BBB- by S&P, and no guarantee obligations had been triggered. If the guarantee obligations were triggered, the maximum amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for Progress Energy's nonregulated portfolio and power supply agreements was approximately $596 million at December 31, 2006. While we believe that we would be able to meet this obligation with cash or letters of credit, if we cannot, our financial condition, liquidity and results of operations would be materially and adversely impacted.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize future financial losses on these contracts as a result of volatility in the market values of the underlying commodities.

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

Our results of operations may be materially affected if our earnings from synthetic fuels are reduced due to the high price of oil. Our ability to utilize tax credits may be limited. This risk is not applicable to PEC and PEF.

Section 29/45K provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold value (the Threshold Price), the amount of Section 29/45K tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation.

In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The contracts will be marked-to-market with changes in fair value recorded through earnings. Our synthetic fuels production levels for 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2007. We will continue to monitor the environment surrounding synthetic fuels production and will adjust our production as warranted by changing conditions.

In accordance with the provisions of Section 29/45K, we have generated tax credits based on the content and quantity of synthetic fuels produced and sold. This tax credit program is scheduled to expire at the end of 2007. We have received favorable private letter rulings from the IRS on all of our synthetic fuels facilities. In order to claim credits under Section 29/45K, among other things, we must produce qualifying fuel and sell our production to unrelated parties. 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 synthetic fuels tax credits, the value of credits generated could be unfavorably impacted by such legislation or IRS regulations and interpretations.

We previously sold a portion of our interests in our synthetic fuels facilities and expect to receive cash payments from the sales through 2008, subject to production levels. We continue to operate these facilities on our own behalf and on behalf of others and consequently, continue to bear the operational risks from the synthetic fuels facilities. We also provided certain guarantees and indemnities in conjunction with our sale of interests in those synthetic fuels facilities. Further, we also operate several synthetic fuels facilities for third parties and also bear operational risk for such facilities.

We are subject to risks from the operation of our nonregulated plants, including dependence on third parties and related counterparty risks, all of which may make our nonregulated generation and overall operations less profitable and more unstable. These risks are not applicable to PEC and PEF.

On December 13, 2006, Progress Energy's board of directors approved a plan to pursue the disposition of substantially all of PVI's CCO physical and commercial assets. CCO currently owns four electricity generation facilities with approximately 1,900 MW of generation capacity, and it has contractual rights to an additional 2,500 MW of generation capacity from mixed fuel generation facilities. CCO also has forward gas and power contracts, gas transportation, storage and structured power and other contracts, including its full requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts). The disposition plan is expected to be completed in 2007. The operation of nonregulated generation facilities is subject to many risks, including those listed below. Until the completion of our disposition strategy, we are subject to risks, including:

- CCO has entered into long-term agreements to sell all or a portion of their generating capacity. CCO has contracts for its combined production capacity of approximately 81 percent for 2007. We anticipate that a third party will acquire these contracts as part of our divestiture strategy. Prior to divestiture of the facilities, uncontracted generation from our facilities will generally be sold on the spot market. CCO may not be able to find adequate purchasers, attain favorable pricing, or otherwise compete effectively in the wholesale market. Additionally, numerous legal and regulatory limitations restrict our ability to operate a facility on a wholesale basis. If CCO divests of its generation facilities, but not the Georgia Contracts, CCO will continue to fulfill the contractual obligation through tolling agreements or purchases in the spot market at then-prevailing prices. If we are unable to secure favorable pricing in the spot market, our results of operations could be negatively impacted.

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

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

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

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

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

Our nonregulated energy marketing and trading operations are subject to risks that could reduce our revenues and adversely impact our results of operations and financial condition; some of these risks, such as weather-related risks, are beyond our control. Volatile commodity prices could reduce our margins. These risks are not applicable to PEC and PEF.

As discussed above, we are pursuing the disposition of substantially all of CCO's physical and commercial assets. Until the completion of our disposition strategy, we will actively seek to manage the market risk inherent in our nonregulated energy marketing operations. We employ risk management monitoring and control techniques to manage the risks inherent in the business. Nonetheless, adverse changes in energy and fuel prices may result in losses in our earnings or cash flows and adversely affect our financial position. Our marketing and risk management procedures do not completely eliminate risk. In addition, to the extent that we do not cover the entire exposure of our assets or our positions to market price volatility, or our hedging procedures do not work as planned, fluctuating commodity prices could cause our sales and net income to be volatile. As a result, our results of operations and financial position are sensitive to the market risk factors discussed below.

Our fleet of nonregulated power plants sells energy into the spot market, other competitive power markets or on a longer-term contractual basis. We may also enter into contracts to purchase and sell electricity and coal as part of our power marketing and energy trading operations. Our business may also include entering into tolling contracts, long-term contracts that supply customers' full electric requirements, or other contractual structures.

The Georgia Contracts provide a fixed price for the power we supply to the cooperatives. These contracts do not provide a guaranteed rate of return on our capital investments through mandated rates. The cooperative load is dependent on the weather and economy of its service area. We use a combination of callable resources from the cooperatives, open market purchases and our own generating assets to serve this load. The risks in serving full requirements supply contracts at a fixed price include both the variability in commodity prices and the volatility of the cooperative energy demand. While these contracts are partially hedged through fixed price power and gas purchases, our revenues and results of operations from these contracts still depend to some degree upon prevailing market prices for power in our regional markets and surrounding competitive markets. These market prices can fluctuate substantially over relatively short periods of time. We anticipate transferring these contracts to a third party as part of our disposition strategy.

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

Our nonregulated businesses are involved in operations that are subject to significant operational and financial risks that may reduce our revenues and adversely impact our results of operations and financial condition. These risks are not applicable to PEC and PEF.

We are exposed to operational risk resulting from our coal mining and terminal operations. Our coal mining operations are subject to conditions beyond our control that can delay deliveries or increase the cost of mining at particular locations for varying lengths of time. Such conditions include unexpected maintenance problems, key equipment failures and variations in geologic conditions. The states in which we operate coal mines have state programs for mine safety and health regulation and enforcement. Financial risks include our exposure to commodity prices, primarily fuel prices. We actively manage the operational and financial risks associated with these businesses. Nonetheless, adverse changes in fuel prices and operational issues beyond our control may result in losses in our earnings or cash flows and adversely affect our balance sheet.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

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

ELECTRIC - PEC

PEC's 18 generating plants represent a flexible mix of fossil, nuclear, hydroelectric, combustion turbines and combined cycle resources, with a total summer generating capacity of 12,409 MW. Of this total, Power Agency owns 699 MW. On December 31, 2006, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)	Summer Net Capability [a] (in MW)	
STEAM TURBINES							
Asheville	Arden, N.C.	2	1964-1971	Coal	100	383	
Cape Fear	Moncure, N.C.	2	1956-1958	Coal	100	317	
Lee	Goldsboro, N.C.	3	1951-1962	Coal	100	406	
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	741	(b)
Robinson	Hartsville, S.C.	1	1960	Coal	100	180	
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.29 [c]	2,425	(b)
Sutton	Wilmington, N.C.	3	1954-1972	Coal	100	606	
Weatherspoon	Lumberton, N.C.	3	1949-1952	Coal	100	177	
	Total	19				5,235	
COMBINED CYCLE							
Cape Fear	Moncure, N.C.	2	1969	Oil	100	70	
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100	454	
	Total	3				524	
COMBUSTION TURBINES							
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	328	
Blewett	Lilesville, N.C.	4	1971	Oil	100	52	
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	792	
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100	75	
Morehead City	Morehead City, N.C.	1	1968	Oil	100	12	
Richmond	Hamlet, N.C.	5	2001-2002	Gas/Oil	100	777	
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	15	
Roxboro	Semora, N.C.	1	1968	Oil	100	12	
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100	59	
Wayne County	Goldsboro, N.C.	4	2000	Gas/Oil	100	686	
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	132	
	Total	42				2,940	
NUCLEAR							
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,875	(b)
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900	(b)
Robinson	Hartsville, S.C.	1	1971	Uranium	100	710	
	Total	4				3,485	
HYDRO							
Blewett	Lilesville, N.C.	6	1912	Water	100	22	
Marshall	Marshall, N.C.	2	1910	Water	100	5	
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100	86	
Walters	Waterville, N.C.	3	1930	Water	100	112	
	Total	15				225	
TOTAL		83				12,409	

(a) Summer ratings reflect compliance with new NERC reliability standards and are gross of joint ownership interest.
(b) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency's share.
(c) PEC and Power Agency are joint owners of Unit 4 at the Roxboro Plant. PEC's ownership interest in this 698 MW unit is 87.06 percent.

At December 31, 2006, including both the total generating capacity of 12,409 MW and the total firm contracts for purchased power of 1,461 MW, PEC had total capacity resources of approximately 13,870 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 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, 2006, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500 kilovolt (kV) lines and 3,000 miles of 230 kV lines. PEC also had approximately 45,000 circuit miles of overhead distribution conductor and 19,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 12.5 million kilovolt-ampere (kVA) in approximately 2,400 transformers. Distribution line transformers numbered approximately 525,000 with an aggregate capacity of approximately 22.4 million kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil, nuclear, combustion turbine and combined cycle resources with a total summer generating capacity of 8,913 MW. Of this total, joint owners own 117 MW. At December 31, 2006, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability [a] (in MW)
STEAM TURBINES						
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	1,005
Bartow	St. Petersburg, Fla.	3	1958-1963	Gas/Oil	100	444
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,313
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	141
	Total	12				3,903
COMBINED CYCLE						
Hines	Bartow, Fla.	3	1999-2005	Gas/Oil	100	1,456
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	203
	Total	4				1,659
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	50
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	176
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	177
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	643
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	110
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	100 [b]	992 [c]
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	13
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	157
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	150
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	45
	Total	47				2,513
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	838 [c]
	Total	1				838
TOTAL		64				8,913

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

(b) PEF and Georgia Power Company (Georgia Power) are joint owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site. Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year.

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

During 2006, including both the total generating capacity of 8,913 MW and the total firm contracts for purchased power of 2,073 MW, PEF had total capacity resources of approximately 10,986 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22 percent. The joint ownership participants are: City of Alachua – 0.08 percent, City of Bushnell – 0.04 percent, City of Gainesville – 1.41 percent, Kissimmee Utility Authority – 0.68 percent, City of Leesburg – 0.82 percent, Utilities Commission of the City of New Smyrna Beach – 0.56 percent, City of Ocala – 1.33 percent, Orlando Utilities Commission – 1.60 percent and Seminole Electric Cooperative, Inc. – 1.70 percent. PEF and Georgia Power are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City Unit P11. Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year. Otherwise, PEF has good and marketable title to its principal plants and units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEF also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2006, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and about 1,500 miles of 230 kV lines. PEF also had approximately 18,000 circuit miles of overhead distribution conductor and 13,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 16 million kVA in approximately 700 transformers. Distribution line transformers numbered approximately 386,000 with an aggregate capacity of approximately 19 million kVA.

COAL AND SYNTHETIC FUELS

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

Through our subsidiaries, we own and operate a river terminal facility in eastern Kentucky, a railcar-to-barge loading facility in West Virginia, two bulk commodity terminals on the Kanawha River near Charleston, West Virginia, and a bulk commodity terminal on the Ohio River near Huntington, West Virginia.

In connection with our coal operations, we own and operate surface and underground mines, coal processing and loadout facilities in southeastern Kentucky and southwestern Virginia. We control either directly or through our subsidiaries, demonstrated coal reserves of approximately 76.5 million tons. The reserves controlled include substantial quantities of high quality, low-sulfur coal. Our total production of coal during 2006 was approximately 1.8 million tons. We employ both our own miners as well as contract miners in our mining activities.

COMPETITIVE COMMERICAL OPERATIONS

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of CCO's physical and commercial assets. As a result, we have classified CCO's operations as discontinued operations in the accompanying consolidated financial statements for all periods presented (See Note 3F).

At December 31, 2006, CCO had the following nonregulated generation plants in service.

Project	Location	Commercial Operation Date	Configuration/ Number of Units	MW [a]
Monroe Units 1 and 2	Monroe, Ga.	1999-2001	Simple-Cycle, 2	315
Walton	Monroe, Ga.	2001	Simple-Cycle, 3	460
Effingham	Rincon, Ga.	2003	Combined-Cycle, 1	480
Washington	Sandersville, Ga.	2003	Simple-Cycle, 4	600
TOTAL				1,855

[a] Amounts represent CCO's summer rating.

ITEM 3. LEGAL PROCEEDINGS

Legal proceedings are included in the discussion of our business in PART I, Item 1 under "Environmental," and are incorporated by reference herein. See Note 22D for a discussion of certain other legal matters.

During 2006, we did not have any "reportable transactions" as defined under Section 6011 of the Code nor did we incur any penalties related to failing to report such information on our tax returns.

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

None

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

EXECUTIVE OFFICERS OF THE REGISTRANTS AS OF FEBRUARY 28, 2007

Name	Age	Recent Business Experience
*Robert B. McGehee	63	**Chairman and Chief Executive Officer,** Progress Energy, May 2004 and March 2004, respectively, to present. Mr. McGehee joined Progress Energy (formerly Carolina Power & Light Company "CP&L") in 1997 as Senior Vice President and General Counsel. Since that time, he has held several senior management positions of increasing responsibility. Most recently, Mr. McGehee served as President and Chief Operating Officer, having responsibility for the day-to-day operations of our regulated and nonregulated businesses. Prior to that, Mr. McGehee served as President and Chief Executive Officer of Progress Energy Service Company, LLC. Before joining Progress Energy, Mr. McGehee chaired the board of Wise Carter Child & Caraway, a law firm headquartered in Jackson, Miss. He primarily handled corporate, contract, nuclear regulatory and employment matters. During the 1990s, he also provided significant counsel to U.S. companies on reorganizations, business growth initiatives and preparing for deregulation and other industry changes.
William D. Johnson	53	**President and Chief Operating Officer,** Progress Energy, January 2005 to present; Group President, PEC, May 2004 to present; Executive Vice President, PEF, November 2000 to present; Executive Vice President, Florida Progress, May 2004 to present; Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress November 2000 to December 2003. Mr. Johnson has been with Progress Energy (formerly CP&L) since 1992 and served as Group President, Energy Delivery, Progress Energy, January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, October 2002 to December 2003. He also served as Executive Vice President - Corporate Relations & Administrative Services, General Counsel and Secretary of Progress Energy. Mr. Johnson served as Vice President - Legal Department and Corporate Secretary, CP&L from 1997 to 1999. Before joining Progress Energy, Johnson was a partner with the Raleigh office

of Hunton & Williams, where he specialized in the representation of utilities.

Peter M. Scott III	57	**Executive Vice President and Chief Financial Officer,** Progress Energy, May 2000 to present; and May 2000 to December 2003 and November 2005 to present; **President and Chief Executive Officer,** Progress Energy Service Company, LLC, January 2004 to present; Executive Vice President, PEC and PEF, May 2000 to present and CFO of PEC, PEF, FPC and Progress Energy Service Company, LLC, 2000 to 2003, and November 2005 to present. Mr. Scott has been with Progress Energy since May 2000. Before joining Progress Energy, Mr. Scott was the president of Scott, Madden & Associates, Inc., a general management consulting firm headquartered in Raleigh that he founded in 1983. The firm served clients in a number of industries, including energy and telecommunications. Particular practice area specialties for Mr. Scott included strategic planning and operations management.
Fred N. Day IV	63	**President and Chief Executive Officer,** PEC, November 2003 to present; Executive Vice President, PEF, November 2000 to present. Mr. Day oversees all aspects of Carolinas Delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Executive Vice President, PEC and PEF. During his more than 30 years with Progress Energy (formerly CP&L), Mr. Day has held several management positions of increasing responsibility. He was promoted to Vice President - Western Region in 1995.
Clayton S. Hinnant	62	**Senior Vice President and Chief Nuclear Officer**, PEC, June 1998 to present. Mr. Hinnant is also Senior Vice President and Chief Nuclear Officer, PEF, November 2000 and November 2005, respectively to present. Mr. Hinnant joined Progress Energy (formerly CP&L) in 1972 at the Brunswick Nuclear Plant near Southport, N.C., where he held several positions in the startup testing and operating organizations. He left Progress Energy in 1976 to work for Babcock and Wilcox in the Commercial Nuclear Power Division, returning to Progress Energy in 1977. Since that time, he has served in various management positions at three of Progress Energy's nuclear plant sites.
*Jeffrey A. Corbett	47	**Senior Vice President**, PEF, June 15, 2006 to present. Mr. Corbett 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 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 Progress Energy in a number of roles, including General Manager of the Eastern Region and director of Distribution Power Quality and Reliability. Before joining Progress Energy, Corbett spent 17 years with Virginia Power, serving in a variety of engineering and leadership roles.
*Jeffrey J. Lyash	45	**President and Chief Executive Officer, PEF, June 1, 2006 to present.** Mr. Lyash oversees all aspects of PEF's Delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President of PEF from November 2003 through May 2006. Prior to coming to PEF, Mr. Lyash was Vice President - Transmission in Energy Delivery in the Carolinas since January 2002.

Mr. Lyash joined Progress Energy in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations.

John R. McArthur	51	**Senior Vice President, General Counsel and Secretary** of Progress Energy, January 2004 to present. Mr. McArthur oversees the Audit Services, Corporate Communications, Legal, Regulatory and Corporate Relations - Florida, and State Public Affairs departments, and the Environmental and Health and Safety sections. Mr. McArthur is also Senior Vice President and Corporate Secretary, FPC and PEC, and Senior Vice President, PEF and Progress Energy Service Company, LLC, January 1 2004 and December 2002, respectively to present. Previously, he served as Senior Vice President - Corporate Relations (December 2002 to December 2003) and as Vice President - Public Affairs (December 2001 to December 2002). Before joining Progress Energy in December 2001, Mr. McArthur was a member of North Carolina Governor Mike Easley's senior management team, handling major policy initiatives as well as media and legal affairs. He also directed Governor Easley's transition team after the election of 2000. From November of 1997 until November of 2000, Mr. McArthur handled state government affairs in 10 southeastern states for General Electric Co. Prior to joining General Electric Co., Mr. McArthur served as chief counsel in the North Carolina Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Before that, he was a partner at Hunton & Williams.
*Mark F. Mulhern	47	**President,** Progress Energy Ventures, Inc. and Progress Fuels Corporation, March 2005 and April 2006, respectively to present. Mr. Mulhern is responsible for managing the Competitive Commercial Operations and Gas Operations groups of Progress Energy Ventures, Inc. He previously served Progress Energy Ventures, Inc. as Senior Vice President - Competitive Commercial Operations from January 2003 to March 2005. He served Progress Energy as Vice President - Strategic Planning from November 2000 to January 2003. He also served as Vice President and Treasurer of PEC from June 1997 to November 2000.
Paula J. Sims	45	**Senior Vice President**, PEC and PEF, April 2006 to present. Ms. Sims previously served PEC and PEF as Vice President-Fossil Generation from January 2006 to April 2006. Prior to that, she served PEC and PEF as Vice President-Regulated Fuels from December 2004 to December 2005. Ms. Sims served Progress Fuels Corporation as Chief Operating Officer from February 2002 to December 2004 and Vice President-Business Operations and Strategic Planning from June 2001 to February 2002. Prior to joining Progress Energy in 1999, Ms. Sims worked at General Electric for 15 years.
Jeffrey M. Stone	45	**Chief Accounting Officer and Controller,** Progress Energy and FPC, June 2005 to present; Chief Accounting Officer PEC and PEF, June 2005 and November 2005, respectively, to present; Vice President and Controller, Progress Energy Service Company, LLC, January 2005 and June 2005, respectively to present. Mr. Stone previously served as Controller of PEF and

PEC from June 2005 to November 2005. Since 1999, Mr. Stone has served Progress Energy in a number of roles in corporate support including Vice President - Capital Planning and Control; Executive Director - Financial Planning & Regulatory Services, as well as in various management positions with Energy Supply and Audit Services.

Prior to joining Progress Energy, Mr. Stone worked as an auditor with Deloitte & Touche in Charlotte, N.C.

E. Michael Williams	58	**Senior Vice President,** PEC and PEF, June 2000 and November 2000, respectively, to present. Before joining Progress Energy in 2000, Mr. Williams was with Central and Southwest Corp., Inc. and subsidiaries for 28 years and served in various positions prior to becoming Vice President - Fossil Generation in Dallas.
Lloyd M. Yates	46	**Senior Vice President,** PEC, January 2005 to present. Mr. Yates is responsible for managing the four regional vice presidents in the PEC organization. He served PEC as Vice President - Transmission from November 2003 to December 2004. Mr. Yates served as Vice President - Fossil Generation for PEC from November 1998 to November 2003. Before joining Progress Energy in 1998, Mr. Yates was with PECO Energy, where he had served in a number of engineering and management roles over 16 years. His last position with PECO was as general manager - Operations in the power operations group.

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

PART II

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

Progress Energy

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

	High	Low	Dividends Declared
2006			
First Quarter	**$45.31**	**$42.54**	**$0.605**
Second Quarter	**45.16**	**40.27**	**0.605**
Third Quarter	**46.22**	**42.05**	**0.605**
Fourth Quarter	**49.55**	**44.40**	**0.610**
2005			
First Quarter	$45.33	$40.63	$0.590
Second Quarter	45.83	40.61	0.590
Third Quarter	46.00	41.90	0.590
Fourth Quarter	45.50	40.19	0.605

The December 31 closing price of our Common Stock was $49.08 for 2006 and $43.92 for 2005. As of February 23, 2007, we had 61,604 holders of record of Common Stock.

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

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2007 Annual Meeting of Shareholders.

Issuer purchases of equity securities for fourth quarter of 2006 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1) (2)	(b) Average Price Paid Per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (1)
October 1 – October 31	115,435	45.9573	N/A	N/A
November 1 – November 30	3	46.1800	N/A	N/A
December 1 – December 31	–	–	N/A	N/A
Total	115,438	45.9573	N/A	N/A

(1) At December 31, 2006, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.

(2) 115,438 shares were purchased in open-market transactions by the plan administrator to satisfy share delivery requirements under the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) (See Note 10B).

PEC

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

PEF

All shares of PEF's common stock are owned by Florida Progress, and as a result there is no established public trading market for the stock. PEF did not issue or repurchase any equity securities during 2006. During 2006 and 2004, PEF paid quarterly dividends to Florida Progress totaling the amounts shown in PEF's Statements of Common Equity included in the financial statements in PART II, Item 8. During 2005, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 10A and 12B). PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED FINANCIAL DATA

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

Progress Energy

	Years ended December 31				
(in millions, except per share data)	**2006**	2005 [(a)]	2004 [(a)]	2003 [(a)]	2002 [(a)]
Operating results					
Operating revenues	**$9,570**	$9,168	$8,053	$7,470	$7,115
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**514**	721	673	771	546
Net income	**571**	697	759	782	528
Per share data					
Basic earnings					
Income from continuing operations	**$2.05**	$2.92	$2.78	$3.25	$2.51
Net income	**2.28**	2.82	3.13	3.30	2.43
Diluted earnings					
Income from continuing operations	**2.05**	2.92	2.77	3.24	2.50
Net income	**2.28**	2.82	3.12	3.28	2.42
Assets	**$25,701**	$27,062	$26,014	$26,207	$24,366
Capitalization					
Common stock equity	**$8,286**	$8,038	$7,633	$7,444	$6,677
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**10**	36	29	24	10
Long-term debt, net [(b)]	**8,835**	10,446	9,521	9,693	9,522
Current portion of long-term debt	**324**	513	349	868	275
Short-term debt	**–**	175	684	4	695
Total capitalization	**$17,548**	$19,301	$18,309	$18,126	$17,272
Dividends declared per common share	**$2.43**	$2.38	$2.32	$2.26	$2.20

(a) Operating results and balance sheet data have been restated for discontinued operations.
(b) Includes long-term debt to affiliated trust of $271 million at December 31, 2006, and $270 million at December 31, 2005, 2004 and 2003 (See Note 23).

PEC

(in millions)	Years Ended December 31 **2006**	2005	2004	2003	2002
Operating results					
Operating revenues	**$4,086**	$3,991	$3,629	$3,600	$3,554
Net income	**457**	493	461	482	431
Earnings for common stock	**454**	490	458	479	428
Assets	**$12,020**	$11,502	$10,787	$10,938	$10,442
Capitalization					
Common stock equity	**$3,390**	$3,118	$3,072	$3,237	$3,089
Preferred stock – not subject to mandatory redemption	**59**	59	59	59	59
Long-term debt, net	**3,470**	3,667	2,750	3,086	3,048
Current portion of long-term debt	**200**	–	300	300	–
Short-term debt [(a)]	–	84	337	29	438
Total capitalization	**$7,119**	$6,928	$6,518	$6,711	$6,634

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

PEF

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

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

The following combined Management's Discussion and Analysis is separately filed by Progress Energy, Inc. (Progress Energy), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF). Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. As used in this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "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 following Management's Discussion and Analysis contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review Item 1A, "Risk Factors" and "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

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

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments and their primary operations include:

- PEC – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina;
- PEF – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida; and
- Coal and Synthetic Fuels – primarily engaged in the production and sale of coal-based solid synthetic fuels in Kentucky and West Virginia, the operation of synthetic fuels facilities for third parties in West Virginia, and coal terminal services in Kentucky and West Virginia.

The "Corporate and Other" segment is comprised of nonregulated businesses that do not separately meet the requirements as a business segment. It primarily includes the activities of the Parent and Progress Energy Service Company, LLC (PESC), as well as other nonregulated business areas.

STRATEGY

We are an integrated energy company, with our primary focus on the end-use and wholesale electricity markets. We operate in retail utility markets in the southeastern United States and in other fuels markets in the eastern United States. Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. We believe that our two electric utilities, combined with our reduced nonregulated business risk, position us well for long-term growth. We are focused on the following key priorities:

- excelling in the daily fundamentals of our utility business;
- preparing for future baseload capacity due to high growth in our regulated service territories;
- further strengthening our financial flexibility and growth;
- maintaining constructive regulatory relations; and
- executing our remaining divestiture transactions.

A summary of the significant financial objectives or issues impacting us, the Utilities and our remaining nonregulated operations is addressed more fully in the following discussion.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 19 consecutive years, and 31 of the last 32 years. We also seek to continue our efforts to enhance balance sheet strength and flexibility so that we are positioned to accommodate the significant future growth expected at the Utilities.

In the short term, our ability to achieve these objectives will be impacted by, among other things, our ability to manage operation and maintenance (O&M) costs, the successful execution of our remaining divestiture transactions, increased environmental spending requirements, commodity price risk, and the scheduled expiration of the Internal Revenue Code (the Code) Section 29/45K (Section 29/45K) tax credit program for our synthetic fuels business at the end of 2007. Our long-term challenges include continuing our cost-management initiatives to mitigate escalating nonfuel and fuel operating costs, effectively managing capital projects, including those for environmental compliance and baseload capacity growth, achieving sufficient earnings growth to sustain our track record of dividend growth, meeting the need for future baseload capacity in our regulated service territories, achieving regulatory stability and investment recovery at the Utilities and complying with increasingly stringent environmental standards. 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.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities contributed $780 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2006. Partially offsetting the net income contribution provided by the Utilities was a loss of $76 million recorded at our Coal and Synthetic Fuels operations, primarily related to the impairment of our synthetic fuels assets, and a loss of $190 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While our synthetic fuels operations have historically provided significant net earnings driven by the Section 29/45K tax credit program, which is scheduled to expire at the end of 2007, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. The total Section 29/45K credits that have been generated through December 31, 2006, but not yet utilized, are currently carried forward as deferred tax credits and will provide cash flow benefits when utilized. At December 31, 2006, the amount of these deferred tax credits was $847 million. See "Other Matters – Synthetic Fuels Tax Credits" below, Note 22D and Item 1A, "Risk Factors" for additional information on our synthetic fuels operations.

Our total debt to total capitalization ratio calculated from the Consolidated Balance Sheet is 52.2 percent at the end of 2006, a decrease from 57.7 percent at the end of 2005, primarily due to a reduction in total debt with proceeds from asset sales, recovery of storm costs incurred in Florida during 2004, fuel cost recovery, operating cash flow and growth in equity from retained earnings and limited ongoing equity issuances. We expect total capital expenditures for 2007, 2008 and 2009 to be approximately $2.4 billion, $2.5 billion and $2.4 billion, respectively, primarily related to the ongoing Utilities' operations. We believe that operating cash flows plus availability under our credit facilities and shelf registration statements will be sufficient to fund our current business plans in the near term. In the long term, we expect to fund our business plans and any new baseload generation through operating cash flows and a combination of long-term debt, preferred stock and common equity, all of which are dependent on our ability to successfully access capital markets. We may also pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

In 2006, the Parent's, PEC's, and PEF's corporate credit ratings of BBB were affirmed and their ratings outlooks were changed to "positive" from "stable" by Standard & Poor's (S&P). Moody's Investors Service, Inc. (Moody's) upgraded the Parent's outlook to "stable" from "negative" and upgraded PEC's outlook to "positive" from "stable." Fitch Ratings (Fitch) upgraded the senior unsecured credit ratings of the Parent (BBB), PEC (A-) and PEF (A-), changed their ratings outlooks to "stable" and removed the Ratings Watch Positive. See "Credit Rating Matters" and "Guarantees" under "Future Liquidity and Capital Resources" below and Item 1A, "Risk Factors" for more information regarding the potential impact on our financial condition and results of operations resulting from a ratings change.

REGULATED UTILITIES

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

The Utilities operate in the southeastern United States, one of the fastest-growing regions of the country, and had a net increase of approximately 64,000 customers over the past year. However, lower industrial sales related mainly to weakness in the textile sector at PEC have reduced the rate of revenue growth in recent years. We do not expect any significant improvement or further degradation in industrial sales in the near term. These combined factors under normal weather conditions are expected to contribute approximately 1.5 percent to 2.0 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.5 percent to 3.0 percent annual retail kWh sales growth at PEF through at least 2008. The Utilities also seek to maintain their regulated wholesale business through targeted contract renewals and origination opportunities. The Utilities must continue to invest significant capital in additional energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities to support this load growth. Subject to regulatory approval, these investments are expected to increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized that creates the basis for long-term earnings growth in the Utilities. Through 2008, we will meet this load growth at PEC through existing resources and at PEF through the previously planned combined cycle unit of approximately 500 megawatts (MW) at PEF's Hines Energy Complex in 2007. The Utilities expect total capital expenditures for 2007, 2008 and 2009 to be approximately \$2.4 billion, \$2.5 billion and \$2.4 billion, respectively. The Utilities expect to fund their capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent.

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: increasing energy efficiency and investing in the development of new energy resources for the future; modernizing existing plants to produce energy efficiently using state-of-the-art technology; and investing in new generating plants. We estimate that we will require new baseload generation facilities at both PEC and PEF by the middle of the next decade and a combined total of approximately 12,500 MW of additional capacity by 2025, and we are evaluating the best available options for this generation, including advanced design nuclear and clean coal technologies. The considerations that will factor into this decision include construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing. See "Other Matters – Nuclear Matters" for additional information.

We are subject to significant air quality regulations passed by the United States Environmental Protection Agency (EPA) in 2005 that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR). Additionally, at PEC's coal-fired facilities in North Carolina, we are subject to the North Carolina Clean Smokestacks Act enacted in 2002 (Clean Smokestacks Act). Including estimated costs for CAIR, CAMR, CAVR and the Clean Smokestacks Act, we currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or pass-through clauses, could be in excess of \$1.0 billion each at PEC and PEF, respectively, through 2018, which is the latest compliance target date for current air and water quality regulations.

While the Utilities expect retail sales growth in the future, they are facing, and expect to continue to face, rising costs. The Utilities are committed to continuing to effectively manage costs to minimize the expected growth in O&M expenses. The Utilities are allowed to recover prudently incurred fuel costs through the fuel portion of our rates, which are adjusted annually in each state. We are focused on mitigating the impact of rising fuel prices since the under-recovery of fuel costs impacts our cash flows, interest and leverage, and rising fuel costs and higher rates also impact customer satisfaction. Our efforts to mitigate these high fuel costs include our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity.

The Utilities successfully resolved key state regulatory issues in 2006, including fuel recovery filings in South Carolina, North Carolina and Florida and storm cost reserve replenishment in Florida. The Utilities continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC and PEF operate. As part of the Clean Smokestacks Act, PEC is operating under a base rate freeze in North Carolina through 2007. As a result of its 2005 base rate proceeding, PEF's base rate settlement extends through 2009. See Note 7 for further discussion of the Utilities' retail rates.

NONREGULATED BUSINESSES

Our primary nonregulated businesses are Coal and Synthetic Fuels. Earnings of Coal and Synthetic Fuels are impacted largely by the volume of synthetic fuels produced and tax credits generated, and volumes and prices of coal terminal sales.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity, all of which own facilities that produce coal-based solid synthetic fuels as defined under Section 29/45K of the Code. The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for 2007. This possibility is due to a provision of Section 29/45K that provides that if annual average market prices for crude oil exceed certain prices, the amount of tax credits is reduced for that year. In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The contracts will be marked-to-market with changes in fair value recorded through earnings. Our synthetic fuels production levels for 2007 remain uncertain because we cannot predict with any certainty the price of oil for 2007. We will continue to monitor the environment surrounding synthetic fuels production and will adjust our production or consider other alternatives as warranted by changing conditions. See additional discussion of synthetic fuels tax credits in "Application of Critical Accounting Policies and Estimates – Synthetic Fuels Tax Credits," "Other Matters – Synthetic Fuels Tax Credits" and Item 1A, "Risk Factors."

As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, many of our nonregulated business operations have been divested or are in the process of being divested. Consequently, we no longer report a Progress Ventures segment, and the composition of other continuing segments has been impacted by these divestitures. These operations have been classified as discontinued operations in the accompanying financial statements. As of December 31, 2006, the carrying value of long-lived assets of the remaining nonregulated electric generation operations and energy marketing activities and the remaining coal mining operations and other fuels businesses was $573 million.

The Progress Registrants are subject to various risks. For a discussion of their current material risks, see Item 1A, "Risk Factors."

RESULTS OF OPERATIONS

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

OVERVIEW

FOR 2006 AS COMPARED TO 2005 AND 2005 AS COMPARED TO 2004

For the year ended December 31, 2006, our net income was $571 million or $2.28 per share compared to $697 million or $2.82 per share for the same period in 2005. For the year ended December 31, 2006, our income from continuing operations was $514 million compared to $721 million for the same period in 2005. The decrease in income from continuing operations as compared to prior year was due primarily to:

- lower synthetic fuels earnings primarily due to lower tax credits;
- impairment of all of our synthetic fuels assets and a portion of our coal terminal assets, primarily due to high oil prices;
- unfavorable weather at the Utilities;
- the cost incurred to redeem holding company debt;
- unrealized losses recorded on contingent value obligations;
- increased nuclear outage expenses at PEC; and
- the prior year gain on the sale of our utility distribution assets serving the City of Winter Park, Fla. (Winter Park).

Partially offsetting these items were:

- prior year postretirement and severance expenses related to the 2005 cost-management initiative;
- increased retail growth and usage at the Utilities;
- the gain on sale of Level 3 Communications, Inc. (Level 3) stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- the prior year write-off of unrecoverable storm costs at PEF.

For the year ended December 31, 2005, our net income was $697 million or $2.82 per share compared to $759 million or $3.13 per share for the same period in 2004. For the year ended December 31, 2005, our income from continuing operations was $721 million compared to $673 million for the same period in 2004. The increase in income from continuing operations as compared to prior year was due primarily to:

- increased synthetic fuels earnings;
- customer growth at the Utilities;
- favorable weather at the Utilities;
- increased wholesale sales at the Utilities; and
- the gain recorded on the sale of Winter Park utility distribution assets.

Partially offsetting these items were:

- postretirement and severance charges related to the 2005 cost-management initiative;
- the change in accounting estimates for certain capital costs in our distribution operations (Energy Delivery); and
- the write-off of unrecoverable storm costs at PEF.

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

(in millions)	**2006**	Change	2005	Change	2004
PEC	**$454**	$(36)	$490	$32	$458
PEF	**326**	68	258	(75)	333
Coal and Synthetic Fuels	**(76)**	(239)	163	73	90
Total segment profit	**704**	(207)	911	30	881
Corporate and Other	**(190)**	–	(190)	18	(208)
Total income from continuing operations	**514**	(207)	721	48	673
Discontinued operations, net of tax	**57**	82	(25)	(111)	86
Cumulative effect of changes in accounting principles	**–**	(1)	1	1	–
Net income	**$571**	$(126)	$697	$(62)	$759

Cost-Management Initiative

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005. We did not incur any similar charges during 2006. The severance and postretirement charges are primarily included in O&M expense on the Consolidated Statements of Income and will be paid over time.

PROGRESS ENERGY CAROLINAS

PEC contributed segment profits of $454 million, $490 million and $458 million in 2006, 2005 and 2004, respectively. The decrease in profits for 2006 as compared to 2005 is primarily due to the unfavorable impact of weather, higher O&M expense related to nuclear outages, the impact of suspending the allocation of the Parent's income tax benefit not related to acquisition interest expense and 2006 capital project write-offs. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. These were partially offset by postretirement and severance expenses incurred in 2005 related to the 2005 cost-management initiative and increased retail customer growth and usage.

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

REVENUES

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

(in millions) Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**$1,462**	2.8	$1,422	7.4	$1,324
Commercial	**1,004**	6.8	940	5.9	888
Industrial	**711**	3.9	684	3.8	659
Governmental	**91**	4.6	87	6.1	82
Total retail revenues	**3,268**	4.3	3,133	6.1	2,953
Wholesale	**720**	(5.1)	759	32.0	575
Unbilled	**(1)**	–	4	–	10
Miscellaneous	**98**	4.3	94	4.4	90
Total electric revenues	**4,085**	2.4	3,990	10.0	3,628
Less: Fuel revenues	**(1,314)**	–	(1,186)	–	(929)
Revenues excluding fuel	**$2,771**	(1.2)	$2,804	3.9	$2,699

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

(in thousands of MWh) Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**16,259**	(2.4)	16,664	4.1	16,003
Commercial	**13,358**	0.3	13,313	2.3	13,019
Industrial	**12,393**	(2.5)	12,716	(2.5)	13,036
Governmental	**1,419**	0.6	1,410	(1.5)	1,431
Total retail energy sales	**43,429**	(1.5)	44,103	1.4	43,489
Wholesale	**14,584**	(6.9)	15,673	18.5	13,222
Unbilled	**(137)**	–	(235)	–	91
Total MWh sales	**57,876**	(2.8)	59,541	4.8	56,802

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

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

Industrial electric energy sales decreased in 2006 compared to 2005 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation. Industrial electric energy sales decreased in 2005 when compared to 2004 primarily due to the reduction in textile manufacturing in the Carolinas and lower demand for both pulp and paper products. The increase in industrial revenues for 2006 compared to 2005 and 2005 compared to 2004 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $1.507 billion for 2006, which represents a $117 million increase compared to 2005. Fuel used in electric generation increased $137 million to $1.173 billion compared to 2005. This increase is due to a $141 million increase in deferred fuel expense partially offset by a $5 million decrease in fuel used in generation. Deferred fuel expense increased as a result of an increase in North Carolina and South Carolina fuel recovery rates. Fuel used in generation decreased primarily due to lower system requirements. See "Electric – PEC – Fuel and Purchased Power" in Item 1, "Business" for a summary of average fuel costs. Purchased power expenses decreased $20 million to $334 million compared to prior year. The decrease in purchased power is due primarily to a change in volume as a result of lower system requirements.

Fuel and purchased power expenses were $1.390 billion for 2005, which represents a $253 million increase compared to 2004. Fuel used in electric generation increased $200 million to $1.036 billion compared to 2004. This increase was due to a $308 million increase in fuel used in generation due to higher fuel costs, a change in generation mix and increased volume. Higher fuel costs were driven primarily by an increase in coal and natural gas prices. Outages at several facilities during 2005 resulted in increased combustion turbine generation, which had a higher average fuel cost. The increase in fuel used in generation was offset by a reduction in deferred fuel expense as a result of the under-recovery of 2005 fuel costs. Purchased power expenses increased $53 million to $354 million compared to 2004. The increase in purchased power was due primarily to a change in volume partially offset by a decrease in price.

Operation and Maintenance

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

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

Depreciation and Amortization

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

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

Taxes Other than on Income

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

Taxes other than on income were $178 million for 2005, which represents a $5 million increase compared to 2004 primarily due to higher payroll taxes of $5 million.

Other

Other operating expenses consisted of a gain of $1 million in 2006 compared to a gain of $11 million in 2005, and a gain of $12 million in 2004. The decrease in the 2006 gain is primarily due to fewer land sales.

Total Other Income (Expense)

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

Total other income (expense) was $7 million of expense in 2005 compared to $3 million of income for 2004. The $10 million increase in expense for 2005 compared to 2004 was primarily due to the $16 million indemnification liability discussed above and $4 million related to an audit settlement with the FERC. These were partially offset by a $7 million write-off of nontrade receivables in 2004.

Total Interest Charges, Net

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

Income Tax Expense

Income tax expense was $265 million, $239 million and $239 million in 2006, 2005 and 2004, respectively. The $26 million income tax expense increase in 2006 compared to 2005 is primarily due to the allocation of $23 million of the Parent's tax benefit not related to acquisition interest expense in 2005 that is no longer allocated in 2006. See

Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

PROGRESS ENERGY FLORIDA

PEF contributed segment profits of $326 million, $258 million and $333 million in 2006, 2005 and 2004, respectively. The increase in profits for 2006 as compared to 2005 is primarily due to the impact of postretirement and severance costs incurred in 2005, increased retail customer growth and usage, an increase in rental and other miscellaneous service revenues and the impact of the 2005 write-off of unrecoverable storm costs. These were partially offset by the 2005 gain on the sale of the utility distribution assets serving Winter Park, the unfavorable impact of weather on revenues and the impact of suspending the allocation of the Parent's tax benefit not related to acquisition interest expense. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

The decrease in 2005 profits as compared to 2004 is primarily due to higher O&M expenses (as a result of postretirement and severance costs, the change in accounting estimates for certain Energy Delivery capital costs, the write-off of unrecoverable storm costs and costs associated with outages) and lower average usage per retail customer partially offset by the favorable impact of weather, higher wholesale sales, the gain on the sale of the utility distribution assets serving Winter Park, and increased retail customer growth.

REVENUES

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

(in millions) Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**$2,361**	18.0	$2,001	10.8	$1,806
Commercial	**1,152**	21.5	948	11.1	853
Industrial	**346**	21.8	284	11.8	254
Governmental	**301**	24.4	242	14.7	211
Revenue sharing refund	**1**	–	(1)	–	(11)
Total retail revenues	**4,161**	19.8	3,474	11.6	3,113
Wholesale	**319**	(7.3)	344	28.4	268
Unbilled	**(5)**	–	(6)	–	7
Miscellaneous	**164**	14.7	143	4.4	137
Total electric revenues	**4,639**	17.3	3,955	12.2	3,525
Less: Fuel and other pass-through revenues	**(3,038)**	–	(2,385)	–	(2,007)
Revenues excluding fuel	**$1,601**	2.0	$1,570	3.4	$1,518

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

(in thousands of MWh) Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**20,021**	0.6	19,894	2.8	19,347
Commercial	**11,975**	0.3	11,945	1.8	11,734
Industrial	**4,160**	0.5	4,140	1.7	4,069
Governmental	**3,276**	2.4	3,198	5.1	3,044
Total retail energy sales	**39,432**	0.7	39,177	2.6	38,194
Wholesale	**4,533**	(17.0)	5,464	7.1	5,101
Unbilled	**(234)**	–	(205)	–	358
Total MWh sales	**43,731**	(1.6)	44,436	1.8	43,653

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

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

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $2.601 billion in 2006, which represents a $584 million increase compared to 2005. Fuel used in electric generation increased $512 million due to a $552 million increase in deferred fuel expense resulting from an increase in the fuel recovery rates on January 1, 2006. This was partially offset by a $41 million decrease in current year fuel costs due primarily to lower system requirements. See "Electric-PEF –Fuel and Purchased Power" in Item 1, "Business" for a summary of average fuel costs. Purchased power expense increased $72 million primarily due to a $48 million increase in current year purchased power costs resulting from higher market prices and a $23 million increase in the recovery of deferred capacity costs.

Fuel and purchased power expenses were $2.017 billion in 2005, which represents a $275 million increase compared to 2004. This increase was due to increases in fuel used in electric generation and purchased power expenses of $148 million and $127 million, respectively. Higher system requirements and increased fuel costs in 2005 accounted for $342 million of the increase in fuel used in electric generation. The increase in fuel used in generation was offset by a reduction in deferred fuel expense as a result of the under-recovery of 2005 fuel costs. Purchased power increased primarily due to higher prices of purchases in 2005 as a result of increased fuel costs.

Operation and Maintenance

O&M expenses were $684 million in 2006, which represents a $168 million decrease compared to 2005. The decrease is primarily due to a $102 million impact of postretirement and severance costs associated with the cost-management initiative in 2005, $24 million of lower environmental cost-recovery expenses due to a decrease in emission allowances and lower recovery rates, $17 million related to the 2005 write-off of unrecoverable storm restoration costs (See Note 7C), a $9 million decrease in nuclear outage costs and a $6 million impact related to the 2005 write-off of GridFlorida regional transmission organization (RTO) startup costs that were previously recovered in revenues. The environmental cost-recovery expenses are recovered through an environmental cost-recovery clause and, therefore, have no material impact on earnings.

O&M expenses were $852 million in 2005, which represents a $222 million increase when compared to 2004. Postretirement and severance costs associated with the cost-management initiative increased O&M costs by $102 million during 2005. In addition, PEF wrote off $17 million of unrecoverable storm costs associated with the 2004 hurricanes (See Note 7C). O&M expense also increased $37 million primarily related to the change in accounting estimates for certain Energy Delivery capital costs and increased $26 million due to higher environmental cost-recovery expenses (primarily emission allowances). The remaining increase in O&M expense is attributable to $9 million of expenses related to outages in 2005, an $8 million workers' compensation benefit adjustment recorded in 2005, $6 million related to the 2005 write-off of GridFlorida RTO startup costs that were previously recovered, and $5 million of additional bad debt expense.

Depreciation and Amortization

Depreciation and amortization expense was $404 million for 2006, which represents an increase of $70 million compared to 2005, primarily due to a $72 million increase in the amortization of storm restoration costs (See Note 7C) and a $48 million increase in utility plant depreciation partially offset by a $51 million decrease in expenses related to cost of removal primarily due to rate changes resulting from the 2005 depreciation study effective January 1, 2006 (See Note 5D). Storm restoration cost amortization is recovered in revenues through the storm recovery surcharge and, therefore, has no material impact on earnings.

Depreciation and amortization expense was $334 million for 2005, which represents an increase of $53 million compared to 2004 primarily due to the amortization of $50 million in storm restoration costs that began in August 2005 (See Note 7C).

Taxes Other than on Income

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

Taxes other than on income were $279 million in 2005, which represents an increase of $25 million compared to 2004. This increase was due to increases in gross receipts and franchise taxes of $8 million each, related to an increase in revenues, a $5 million increase in payroll taxes and an increase in property taxes of $3 million.

Other

Other operating expenses were a gain of $2 million in 2006 compared to a gain of $26 million in 2005 and a gain of $2 million in 2004. Both the decrease in the gain for 2006 compared to 2005 and the increase in the gain from 2005 compared to 2004 are primarily due to the $24 million gain on the sale of the utility distribution assets serving Winter Park recorded in 2005.

Total Other Income

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

Total Interest Charges, Net

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

Total interest charges, net were $126 million in 2005, which represents an increase of $12 million compared to 2004. The increase in interest expense was primarily due to increased commercial paper borrowings and a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $193 million, $121 million and $174 million in 2006, 2005 and 2004, respectively. The $72 million income tax expense increase in 2006 compared to 2005 is primarily due to changes in pre-tax income. In addition, 2005 income tax expense included the allocation of $13 million of the Parent's tax benefit not related to acquisition interest expense that is no longer allocated in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. Fluctuations in income tax expense between 2005 and 2004 are primarily due to changes in pre-tax income.

COAL AND SYNTHETIC FUELS

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

(in millions)	**2006**	2005	2004
Synthetic fuels operations	**$(44)**	$155	$92
Coal terminals and marketing	**12**	43	34
Corporate overhead and other operations	**(44)**	(35)	(36)
Segment (loss) profits	**$(76)**	$163	$90

SYNTHETIC FUELS OPERATIONS

The production and sale of synthetic fuels generate operating losses, but qualify for tax credits under Section 29/45K, which generally more than offset the effect of such losses (See "Other Matters – Synthetic Fuels Tax Credits" below).

Results from the synthetic fuels operations are summarized below:

(in millions)	**2006**	2005	2004
Tons sold	**3.7**	10.1	8.3
After-tax losses (excluding impairment charge, valuation allowance and tax credits)	**$(68)**	$(147)	$(128)
After-tax gain on sale of assets	**3**	20	5
After-tax impairment charge	**(45)**	–	–
Net operating loss (NOL) valuation allowance	**(13)**	–	–
Tax credits generated	**107**	267	215
Tax credit inflation adjustment	**10**	5	–
Tax credit reserve increase due to estimated phase-out	**(38)**	–	–
Tax credits previously unrecorded	**–**	10	–
Net (loss) profit	**$(44)**	$155	$92

Prior to 2006, our synthetic fuels production levels and the amount of tax credits we could claim each year were limited by our consolidated regular federal income tax liability. With the redesignation of Section 29 tax credits as Section 45K general business credits, that limitation was removed effective January 1, 2006.

Synthetic fuels operations' net (loss) profit changed from a profit of $155 million in 2005 to a loss of $44 million in 2006 primarily due to lower synthetic fuels production as a result of high oil prices, which increased the potential phase-out of tax credits. The 6.4 million ton decrease in synthetic fuels production resulted in $79 million of lower after-tax losses. The decision to idle our synthetic fuels facilities necessitated an impairment test and resulted in the impairment of our synthetic fuels assets (See Notes 8 and 9). The lower production also resulted in a $160 million reduction in generated tax credits, and as a result of the high oil prices, we recorded a $38 million tax credit reserve due to the estimated phase-out. The higher 2006 average oil prices and the uncertainty of the final phase-out percentage for 2006 resulted in a $17 million after-tax decrease in our gain on sale of assets due to recognizing a lower gain on the monetization of the Colona Synfuel Limited Partnership, LLLP (Colona) facility compared to 2005 (See Note 3J). The gain for 2006 is expected to be recorded in 2007 when the final phase-out percentage has been calculated. As of December 31, 2006, $7 million of deferred gain was recorded on the Consolidated Balance Sheet. In addition, results were unfavorably impacted by the recognition of a valuation allowance recorded against the deferred tax assets for state operating loss carry forwards. Due to the impairment of our synthetic fuels assets, the impairment charge included approximately $12 million of depreciation and amortization expense that would otherwise have been recorded in 2006, and $25 million of depreciation and amortization expense that would otherwise have been recorded during 2007.

Synthetic fuels operations' net (loss) profits increased in 2005 as compared to 2004 due primarily to an increase in synthetic fuels production and an additional $23 million pre-tax gain recognized on the monetization of the Colona facility compared to 2004 (See Note 3J), partially offset by an increase in operating expenses. In addition, earnings in 2005 include a $10 million favorable tax credit true-up related to 2004. Our total synthetic fuels production of approximately 10 million tons in 2005 is greater than 2004 production levels of approximately eight million tons as a result of hurricane costs in 2004, which reduced our projected 2004 regular tax liability and our corresponding ability to record tax credits from synthetic fuels production.

Our future synthetic fuels production levels for 2007 remain uncertain due to the recent volatility of oil prices. See "Other Matters – Synthetic Fuels Tax Credits" below for additional information on the impact of oil prices on Section 29/45K tax credits, the results of our interim impairment review and a discussion of uncertainties surrounding our synthetic fuels production in 2007.

COAL TERMINALS AND MARKETING

Coal terminals and marketing (Coal) operations blend and transload coal as part of the trucking, rail and barge network for coal delivery. This business also has an operating fee agreement with our synthetic fuels operations for procuring and processing of coal and the transloading and marketing of synthetic fuels. As a result of the relationship with the synthetic fuels operations, fluctuations in Coal's annual earnings are primarily related to production volumes at our synthetic fuels facilities. Coal operations contributed earnings of $12 million, $43 million and $34 million in 2006, 2005 and 2004, respectively. Coal's 2006 results were negatively impacted by the impairment of a portion of Coal's terminal assets, which resulted in a pre-tax charge of $17 million ($10 million after-tax) and lower revenues related to lower production at our synthetic fuels facilities and higher cost of sales due to higher coal prices (See Note 9). These were partially offset by an $11 million pre-tax reduction in expense related to a restructured coal supply contract due to 2005 coal commitments that were not delivered. During the first quarter of 2006, one of Coal's supply contracts was restructured resulting in a payment of $103 million to Coal. These proceeds covered long-term coal supply commitments from 2005 through 2007 and will be recognized over the life of the contract as coal is received and the related inventory is utilized. Future amortization of these proceeds will be wholly offset by the increased contract price and is therefore not expected to materially impact earnings. As a result of the impairment of Coal's terminal assets discussed above, the impairment charge included approximately $6 million of depreciation expense that would otherwise have been recorded in 2006 and approximately $11 million of depreciation expense that would otherwise have been recorded during 2007. The Coal and Synthetic Fuels segment has long-term fixed price coal purchase contracts to provide a portion of the feedstock coal required to meet 2007 solid synthetic fuels production or to resell as coal. As a result, the 2006 decline in coal prices is expected to negatively impact the financial performance of the Coal and Synthetic Fuels segment compared to previous years.

The increase in earnings for 2005 compared to 2004 was primarily due to additional revenues at the coal terminals related to increased prices and volumes and additional intersegment fees for both the coal terminals and marketing operations due to increased synthetic fuels production. These were partially offset by an increase in the cost of coal purchased by the coal terminals operations due to increased prices and larger volumes and lower third-party sales by the marketing operations.

CORPORATE OVERHEAD AND OTHER OPERATIONS

Corporate overhead and other operations incurred losses of $44 million, $35 million and $36 million for the years ended December 31, 2006, 2005 and 2004, respectively. The increase in losses for 2006 compared to 2005 is primarily due to the decreased allocation of interest and overheads to discontinued operations as a result of the divestitures completed during 2006.

CORPORATE AND OTHER

The Corporate and Other segment consists of the operations of the Parent, PESC and other consolidating and nonoperating entities (Corporate). Corporate and Other also includes other nonregulated business areas. Corporate and Other income (expense) is summarized below:

(in millions)	**2006**	Change	2005	Change	2004
Other interest expense	**$(246)**	$(12)	$(234)	$6	$(240)
Contingent value obligations	**(25)**	(31)	6	(3)	9
Tax reallocation	**–**	38	(38)	(1)	(37)
Other income tax benefit	**109**	26	83	(21)	104
Other expense	**(28)**	(21)	(7)	37	(44)
Corporate and Other after-tax expense	**$(190)**	$–	$(190)	$18	$(208)

Other interest expense, which includes elimination entries, increased $12 million for 2006 compared to 2005 primarily due to a decrease in the interest allocated to discontinued operations and a decrease in the elimination of intercompany interest expense due to lower intercompany debt balances partially offset by lower interest expense due to lower holding company debt. The decrease in interest expense allocated to discontinued operations resulted from the full year allocations of interest expense in 2005 compared to partial year allocations of interest in 2006 for operations that were sold in 2006. The decrease in other interest expense for 2005 compared to 2004 is primarily due to the increase in the interest allocated to discontinued operations partially offset by a decrease in interest rate swap activity that benefited from lower variable rates during 2004.

Progress Energy issued 98.6 million contingent value obligations (CVOs) in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash flows the facilities generate. At December 31, 2006, 2005 and 2004, the CVOs had a fair market value of approximately $32 million, $7 million and $13 million, respectively. Progress Energy recorded an unrealized loss of $25 million for 2006 and unrealized gains of $6 million and $9 million for 2005 and 2004, respectively, to record the changes in fair value of CVOs, which had average unit prices of $0.33, $0.07 and $0.14 at December 31, 2006, 2005 and 2004, respectively.

For the year ended December 31, 2006, income tax expense was not increased by the allocation of the Parent's income tax benefits not related to acquisition interest expense to profitable subsidiaries. Due to the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), beginning in 2006 we no longer allocate the Parent income tax benefits not related to acquisition interest expense to profitable subsidiaries. Since 2002, Parent income tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a PUHCA 1935 order. For the years ended December 31, 2005 and 2004, income tax expense was increased by $38 million and $37 million, respectively, due to the allocation of the Parent's income tax benefit.

Other income tax benefit increased for 2006 compared to 2005 primarily due to increased pre-tax expense at the Parent. Other income tax benefit decreased for 2005 compared to 2004 due primarily to lower pre-tax expense at the Parent.

For 2006, other expense was $28 million compared to $7 million in 2005. The $21 million change is primarily due to the $59 million pre-tax ($35 million after-tax) loss on redemption of holding company debt (See Note 12) partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC (See Note 3D). In addition, other expense changed due to a $14 million increase in interest income on temporary investments due to proceeds from the sale of DeSoto County Generating Co., LLC (DeSoto), Rowan County Power, LLC (Rowan) and Gas. The $37 million decrease in other expense from 2004 to 2005 was primarily due to the $43 million pre-tax ($29 million after-tax) settlement agreement in 2004 that our subsidiary Strategic Resource Solutions Corp. reached with the San Francisco United School District related to civil proceedings.

DISCONTINUED OPERATIONS

Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. We divested, or announced divestitures, of multiple nonregulated businesses during 2006 in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities. Consequently, we no longer report a Progress Ventures segment, and the composition of other continuing segments has been impacted by these divestitures.

CCO OPERATIONS

CCO – Georgia Operations

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of Progress Energy Ventures, Inc.'s (PVI) Competitive Commercial Operations (CCO) physical and commercial assets, which include approximately 1,900 megawatts of power generation facilities in Georgia, as well as forward gas and power contracts, gas transportation, storage and structured power and other contracts, including full requirement contracts with 16 Georgia Electric Membership Cooperatives (the Georgia Contracts). We expect to complete the disposition plan in 2007. As a result of the disposition plan, we recorded an after-tax estimated loss on the sale of $226 million in December 2006, which includes an impairment charge related to the generation assets and intangible assets to reduce the carrying value of the assets that are expected to be sold to their estimated fair value less cost to sell (See Note 3A).

In 2007, we anticipate recording additional material charges in discontinued operations related to the disposition plan. These additional charges relate primarily to costs to be incurred to exit the Georgia Contracts. These costs could exceed $200 million after-tax. If CCO divests of its generation facilities but not the Georgia Contracts, CCO will continue to fulfill the contractual obligation through tolling agreements or purchases in the spot market.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet (Bcf) of natural gas would be fulfilled. Therefore, these contracts were no longer treated as hedges and were dedesignated, and cash flow hedge accounting was discontinued. Changes in market prices since inception resulted in the recognition of unrealized mark-to-market gains of $92 million pre-tax ($60 million after-tax) for 2006. Future price volatility in the natural gas market will cause us to record mark-to-market changes through earnings of discontinued operations and will increase the volatility of future CCO operating results.

CCO's operations generated net losses from discontinued operations of $57 million in 2006, $54 million in 2005 and $23 million in 2004. The increase in loss for 2006 compared to 2005 is primarily due to the $64 million pre-tax impairment loss ($42 million after-tax) on goodwill recognized in the first quarter of 2006 (See Note 8) and an increase in realized mark-to-market losses on gas hedges due to gas price volatility. This was partially offset by a higher gross margin related to serving the fixed price full requirements contracts that began in April 2005 and serving an increased load on a pre-existing contract in Georgia, and $66 million pre-tax of unrealized mark-to-market gains, primarily related to the dedesignated natural gas hedges discussed above.

The increase in loss for 2005 compared to 2004 is due primarily to a reduction in gross margin of $79 million pre-tax ($47 million after-tax) partially offset by favorable amortization and interest expense fluctuations. Contract margins were unfavorable in 2005 compared to 2004 due to the expiration of certain above-market tolling agreements and decreased earnings from new and existing full requirements contracts due to higher fuel and purchased power costs partially offset by net realized and unrealized mark-to-market gains. Depreciation and amortization expenses decreased $6 million pre-tax ($4 million after-tax) as a result of the expiration of certain acquired contracts that were subject to amortization.

CCO – DeSoto and Rowan Generation Facilities

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

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. We recorded an after-tax loss of $67 million during the year ended December 31, 2006, on the sale of DeSoto and Rowan. Discontinued DeSoto and Rowan operations had combined earnings of $10 million, $3 million and $8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

GAS OPERATIONS

On July 12, 2006, our board of directors approved a plan to divest of our natural gas drilling and production business (Gas), which includes Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all are subsidiaries of Progress Fuels Corporation (Progress Fuels). On July 22, 2006, we entered into a definitive agreement to sell Gas to EXCO Resources, Inc. for $1.2 billion in gross cash proceeds. We recorded an after-tax gain of $300 million during the year ended December 31, 2006, on the sale of Gas. Proceeds from the sale were used primarily to reduce holding company debt and for other corporate purposes (See Note 3B).

The transaction closed on October 2, 2006. Specific assets included over 325 Bcf equivalent of proved natural gas reserves, over 350 miles of pipelines, over 500 producing wells and other related assets, all of which were located in Texas and Louisiana. Discontinued Gas operations had net earnings from discontinued operations of $82 million for the year ended December 31, 2006, compared to net earnings from discontinued operations of $48 million for the same period in 2005. The increase in net earnings is primarily due to increased production, higher market prices and mark-to-market gains on gas hedges.

Gas operations generated profits of $48 million for the same period in 2005 compared to $76 million for the year ended December 31, 2004. The decrease is primarily due to the gain recognized on the sale of gas assets in 2004. In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production (North Texas gas operations). Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting the pre-tax gain of $56 million ($31 million net of taxes) was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. In addition, lower sales and general and administrative expense and interest expenses partially offset by lower revenues reduced the overall earnings decline from 2004 to 2005. Revenues were lower in 2005 due to the sale of the North Texas gas operations; however, the Texas/Louisiana gas operations were able to offset a majority of the lost revenue due to higher natural gas prices and increased production.

PROGRESS TELECOM, LLC

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

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an estimated after-tax gain on disposal of $28 million during the year ended December 31, 2006. Net (loss) earnings from discontinued operations for PT LLC were a loss of $2 million, earnings of $4 million and a loss of $7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold our 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units under long-term contracts with PEF. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels. The other fuels business is expected to be sold in 2007 (See Note 3E).

Net earnings from discontinued operations for Dixie Fuels and other fuels business were $7 million, $5 million and $2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

COAL MINING BUSINESSES

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an estimated after-tax loss of $10 million for the sale of these assets. The remaining coal mining operations are expected to be sold in 2007 (See Note 3F).

Net losses from discontinued operations for the coal mining business were $4 million, $11 million and $5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

PROGRESS RAIL

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. During the years ended December 31, 2006 and 2005, we recorded an estimated after-tax loss for the sale of these assets of $6 million and $25 million, respectively. Proceeds from the sale were used to reduce debt (See Note 3G).

Net earnings from discontinued operations for Rail were $5 million and $29 million for the years ended December 31, 2005 and 2004. Rail did not have a material impact on earnings for the year ended December 31, 2006.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

UTILITY REGULATION

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

ASSET IMPAIRMENTS

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

The carrying value of our total utility plant, net is $15.245 billion at December 31, 2006. The carrying value of our total diversified business property, net is $31 million at December 31, 2006. In addition, we have certain diversified business property with a carrying value of $573 million at December 31, 2006, included in net assets of discontinued operations (See Note 3H). Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) does not exceed total capitalized costs, we are required to write-down capitalized costs to the ceiling. We performed this ceiling test calculation every quarter prior to the sale of the Gas Operations (See Note 3B). No write-downs were required in 2006 or 2005.

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

GOODWILL

As discussed in Note 8, we account for goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2006 and 2005, each of which indicated no impairment. If the fair values for the utility segments were lower by five percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2006 and 2005, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

For our former Progress Ventures segment, the goodwill impairment tests were performed at our Georgia Region reporting unit level, which was comprised of four nonregulated generation plants and was one level below the Progress Ventures segment. We performed the annual goodwill impairment test for our Georgia Region reporting unit in the first quarters of 2006 and 2005. The test in 2005 indicated no impairment. In 2006, the test indicated that goodwill was fully impaired, and we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006.

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

SYNTHETIC FUELS TAX CREDITS

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

In addition, Section 29/45K provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold value (the Threshold Price), the amount of tax credits is reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. We estimate that the 2006 Annual Average Price will result in an approximate 35 percent phase-out of the synthetic fuels tax credits related to synthetic fuels production in 2006. This estimate is derived from our estimates of the 2006 Threshold Price and Phase-out Price of $55 per barrel and $69 per barrel, respectively, based on an estimated inflation adjustment for 2006. For 2007 synthetic fuels production, the 2007 Annual Average Price is not known until after the end of the year; we will record the 2007 tax credits based on our estimates of what we believe the Annual Average Price will be for 2007. These estimates are based on oil prices in the futures market. Any portion of the tax credits that would be phased out based on the projected 2007 Annual Average Price exceeding the Threshold Price will not be recorded.

We estimate that the 2007 Threshold Price will be approximately $56 per barrel and the Phase-out Price will be approximately $70 per barrel, based on estimated inflation adjustments for 2006 and 2007. The monthly Domestic Crude Oil First Purchases Price published by the Energy Information Agency (EIA) has recently averaged approximately $7 lower than the corresponding daily New York Mercantile Exchange (NYMEX) prompt month settlement price for light sweet crude oil. As of January 31, 2007, the average NYMEX futures price for light sweet crude oil for calendar year 2007 was $59.50 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price, if oil prices for the rest of 2007 remained at the January 31, 2007, average 2007 futures price level of $59.50 per barrel, we currently estimate that the synthetic fuels tax credit amount for 2007 would not be reduced. See further discussion in "Other Matters – Synthetic Fuels Tax Credits" and Item 1A, "Risk Factors."

PENSION COSTS

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

Due to an increase in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, we increased the discount rate to approximately 5.95% at December 31, 2006, from approximately 5.65% at December 31, 2005, which will decrease the 2007 benefit costs recognized, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study by our actuary, which matches our projected benefit payments to a high-quality corporate yield curve. Plan assets performed well in 2006, with returns of approximately 14%. That positive asset performance will result in decreased pension costs in 2007, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2007 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2007 will be $22 million to $30 million, compared with $32 million recognized in 2006.

We have pension plan assets with a fair value of approximately $1.8 billion at December 31, 2006. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2005, we elected to lower our expected rate of return from 9.25% to 9.0%. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 0.25% change in the expected rate of return for 2006 would have changed 2006 pension costs by approximately $4 million.

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

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Progress Energy, Inc. is a holding company and, as such, has no revenue-generating operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $2.6 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities and our nonregulated subsidiaries, and the ability of our subsidiaries to pay dividends or repay funds to us. Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, primarily generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity.

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

Prior to February 8, 2006, we were a registered holding company under PUHCA 1935, and therefore we obtained approval from the Securities and Exchange Commission (SEC) for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend to and borrow from each other. A nonutility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and nonutility money pools but cannot borrow funds. The Energy Policy Act of 2005 (EPACT) repealed PUHCA 1935 effective February 8, 2006, and transferred to the FERC certain new responsibilities with respect to the regulation of utility holding companies under the Public Utilities Holding Company Act of 2005 (PUHCA 2005). Pursuant to PUHCA 2005, utility holding companies are allowed to continue to engage in financings authorized by the SEC, provided the authorization orders have been filed with the FERC and the holding company continues to comply with such orders, terms and conditions. We have filed all such SEC orders with the FERC; therefore, we are permitted to continue all such financing transactions.

Cash from operations, asset sales, short-term and long-term debt and limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2007. For the fiscal year 2007, we expect to realize an aggregate amount of approximately $50 million from the sale of stock through these plans.

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

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

HISTORICAL FOR 2006 AS COMPARED TO 2005 AND 2005 AS COMPARED TO 2004

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. Net cash provided by operating activities from continuing operations for the three years ended December 31, 2006, 2005 and 2004, was $1.912 billion, $1.175 billion, and $1.409 billion, respectively.

Cash from operating activities for 2006 increased when compared with 2005. The $737 million increase in operating cash flow was primarily due to a $713 million increase in the recovery of fuel costs at the Utilities, a $201 million increase from the change in accounts receivable, approximately $103 million of proceeds received from the restructuring of a long-term coal supply contract, and $72 million related to recovery of storm restoration costs at PEF. These impacts were partially offset by a $122 million net increase in tax payments in 2006 compared to 2005, $141 million related to a wholesale customer prepayment in 2005 at PEC, as discussed below, and a $57 million decrease from the change in accounts payable. The $201 million change in accounts receivable included $147 million at PEC, principally driven by the timing of wholesale sales, and approximately $47 million at PEF, primarily related to timing of receipts.

In 2006 and 2005, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. In 2005, PEF also received approval from the Florida Public Service Commission (FPSC) authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7 for additional information.

Cash from operating activities for 2005 decreased when compared with 2004. The $234 million decrease in operating cash flow was primarily due to a $298 million decrease in the recovery of fuel costs at the Utilities, driven by rising fuel costs, and increased working capital needs of $144 million, partially offset by a $193 million reduction in storm cost spending at PEF in 2005 compared to 2004. Cash from operating activities for 2005 also includes a $141 million prepayment received from a wholesale customer. In November 2005, PEC entered into a contract with the Public Works Commission of the City of Fayetteville, North Carolina (PWC), in which the PWC prepaid $141 million in exchange for future capacity and energy power sales. The prepayment is expected to cover approximately two years of electricity service and includes a prepayment discount of approximately $16 million. In 2005, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. PEF also received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7 for additional information.

The increase in working capital needs for 2005 compared to 2004 was mainly driven by a $170 million increase in the change in receivables, a $97 million increase in prepayments and other current assets, and a $52 million increase in inventory purchases, primarily coal at PEC. These impacts were partially offset by a $133 million increase in the change in accounts payable and the current portion of the prepayment received from the PWC as discussed above. The increase in the change in receivables is primarily due to increased sales at the Utilities driven by weather, rising fuel costs and timing of receipts, and increased sales at our nonregulated subsidiaries, mainly driven by changes in the production level of our synthetic fuels facilities over the prior year. The change in accounts payable is primarily due to higher fuel prices at PEF and increased quantities of coal purchases at our nonregulated subsidiaries.

INVESTING ACTIVITIES

Net cash provided (used) by investing activities for the three years ended December 31, 2006, 2005 and 2004, was $271 million, $(914) million and $(649) million, respectively. Excluding proceeds from sales of discontinued operations and other assets of $1.654 billion in 2006 and $475 million in 2005, cash used in investing activities decreased slightly in 2006 when compared with 2005. The decrease in 2006 was primarily due to a $319 million increase in net proceeds from available-for-sale securities and other investments, a $12 million decrease in nuclear fuel additions, and a $14 million decrease in other investing activities, largely offset by a $343 million increase in capital expenditures for utility property. At PEC, the increase in utility property was primarily due to environmental compliance and mobile meter reading project expenditures. At PEF, the increase in utility property was primarily due to repowering the Bartow plant to more efficient natural gas-burning technology; various distribution, transmission and steam production projects; and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

Utility property additions, including nuclear fuel, for our regulated electric operations were $1.537 billion and $1.206 billion in 2006 and 2005, respectively, or approximately 100 percent of consolidated capital expenditures in both 2006 and 2005. Capital expenditures for our regulated electric operations are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

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

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested, cash used in investing activities increased approximately $368 million in 2005 when compared with 2004. The increase is due primarily to a $254 million decrease in net proceeds from available-for-sale securities and other investments and a $107 million increase in capital expenditures for utility property and nuclear fuel additions. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning and benefit investment trusts.

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

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

FINANCING ACTIVITIES

Net cash (used) provided by financing activities for the three years ended December 31, 2006, 2005 and 2004, was $(2.468) billion, $229 million and $(485) million, respectively. See Note 12 for details of debt and credit facilities.

For 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, were used to reduce holding company debt by $1.7 billion. The increase in cash used in financing activities was primarily related to the retirement of long-term debt in the current year, as discussed below, and a decrease in the proceeds from issuances of long-term debt. For 2005, cash provided by financing activities increased primarily due to additional issuances of long-term debt at the Utilities and an increase in common stock issuances. For 2004, cash from operations exceeded net cash used in investing activities by $760 million due primarily to asset sales, which allowed for a net decrease in cash requirements provided by financing activities.

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

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. Interest on the Floating Rate Senior Notes is based on three-month London Inter Bank Offering Rate (LIBOR) plus 45 basis points and resets quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of proceeds as described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

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

- On March 31, 2006, Progress Energy, as a well-known seasoned issuer, filed a shelf registration statement with the SEC. The registration statement became effective upon filing with the SEC and will allow Progress Energy to issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2006, Progress Energy had the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year revolving credit agreement (RCA) with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006. The new RCA will continue to be used to provide liquidity support for Progress Energy's issuances of commercial paper and other short-term obligations. The new RCA includes a defined maximum total debt to capital ratio of 68 percent and contains various cross-default and other acceleration provisions. The new RCA does not include a material adverse change representation for borrowings or a financial covenant for interest coverage. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's and BBB- by S&P.

- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P. The amended PEC RCA is scheduled to expire on June 28, 2010.

- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB- by S&P. The amended PEF RCA is scheduled to expire on March 28, 2010.

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

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

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

- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.

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

2005

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was subsequently terminated on May 16, 2005. In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent. In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, the $800 million of 6.75% Senior Notes was retired, thus effectively terminating the 364-day credit agreement.

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

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

- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 4.6 million shares for proceeds of approximately $199 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2005, the dividends paid on common stock were approximately $582 million.

2004

- Progress Energy paid at maturity $500 million in 6.55% Senior Notes and entered into a new $1.1 billion five-year line of credit, expiring August 5, 2009. This facility replaced Progress Energy's $250 million 364-day line of credit and its three-year $450 million line of credit, which were both scheduled to expire in November 2004. Proceeds from the sale of natural gas assets were used to extinguish PVI's $241 million bank facility, and Progress Capital Holdings, Inc. paid at maturity $25 million of 6.48% medium-term notes.

- PEC redeemed $35 million of Darlington County 6.6% Series Pollution Control Bonds, $2 million of New Hanover County 6.3% Series Pollution Control Bonds, and $2 million of Chatham County 6.3% Series Pollution Control Bonds. PEC paid at maturity $150 million of 5.875% First Mortgage Bonds and $150 million of 7.875% First Mortgage Bonds. PEC extended to July 27, 2005, its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004.

- PEF paid at maturity $40 million in 6.69% Medium-Term Notes, Series B.

- Progress Energy issued approximately 1.7 million shares of our common stock for approximately $73 million in net proceeds from our Investor Plus Stock Purchase Plan and our employee benefit and stock option plans. Included in these amounts were approximately 1.4 million shares for proceeds of approximately $62 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2004, the dividends paid on common stock were approximately $558 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

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

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2006 and 2005. It is expected that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels operations do not currently produce positive operating cash flow due to the difference in timing of when tax credits are recognized for financial reporting purposes and when tax credits are realized for tax purposes (See "Other Matters – Synthetic Fuels Tax Credits").

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

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

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

At December 31, 2006, the current portion of our long-term debt was $324 million, which we expect to fund with a combination of cash from operations, proceeds from sales of assets, commercial paper borrowings and long-term debt. See Note 3 for additional information on asset sales.

REGULATORY MATTERS AND RECOVERY OF COSTS

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

<u>Base Rates</u>

PEC's base rates are subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. Subsequent to 2007, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation.

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between a specified threshold and specified cap, which will be adjusted annually, and 100 percent of revenues above the specified cap. PEF's retail base revenues did not exceed the specified 2006 threshold, and thus no revenues were subject to revenue sharing. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Additionally, PEF will continue to recover and collect a return on Hines Unit 2 through the fuel clause through late 2007, when it will be transferred into base rates. If PEF's regulatory return on equity (ROE) falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PEC Fuel Cost Recovery

On June 16, 2006, the SCPSC approved a settlement agreement for an increase in the fuel rate charged to PEC's South Carolina ratepayers for under-recovered fuel costs and to meet future expected fuel costs. The settlement agreement provided for a $23 million, or 4.6 percent, increase in rates, effective July 1, 2006. At December 31, 2006, PEC's South Carolina deferred fuel balance was $29 million, of which $5 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

On September 25, 2006, the NCUC approved a settlement agreement for an increase in the fuel rate charged to PEC's North Carolina ratepayers. The settlement agreement provided for a $177 million, or 6.7 percent, increase in rates effective October 1, 2006. The settlement agreement further provides for rate increases of $50 million in 2007 and $30 million in 2008 and for PEC to collect its existing deferred fuel balance by September 30, 2009. PEC initially sought an increase of $292 million, or 11.0 percent, but agreed to a three-year phase-in of the increase in order to address customer concerns regarding the magnitude of the proposed increase. PEC will be allowed to calculate and collect interest at 6% on the difference between its fuel factor proposed in its original request to the NCUC and the settlement agreement's factor. At December 31, 2006, PEC's North Carolina deferred fuel balance was $281 million, of which $109 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset. The Carolina Utility Customers Association (CUCA) has appealed the NCUC's order on the grounds that the NCUC does not have the statutory authority to establish fuel rates for more than one year. We anticipate filing a motion to dismiss during the first quarter of 2007. We cannot predict the outcome of this matter.

PEF Pass-through Clause Cost Recovery

On November 8, 2006, the FPSC approved PEF's supplemental filing resulting in a $40 million, or 0.7 percent, increase over 2006 rates to cover rising fuel, environmental compliance and energy conservation costs. The new charges were effective January 1, 2007. At December 31, 2006, PEF was over-recovered in fuel and capacity costs by $63 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. A hearing on the matter has been scheduled by the FPSC for April 2, 2007. PEF believes that its coal procurement practices were prudent and that it has sound legal and factual arguments to successfully defend its position. We cannot predict the outcome of this matter.

On February 8, 2007, the FPSC issued an order approving PEF's request for a need determination to uprate Crystal River Unit No. 3 Nuclear Plant (CR3). The uprate will take place in two stages in 2009 and 2011 and is estimated to cost approximately $382 million, which includes potential transmission system improvements and modifications to comply with environmental regulations. The FPSC has scheduled a hearing on May 23, 2007, to determine whether the uprate costs should be recovered through the fuel adjustment clause. If PEF does not receive approval to recover the uprate costs through the fuel adjustment clause, these costs will be recoverable through base rates, similar to other utility plant additions. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC), which were estimated to be $43 million at December 31, 2006. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR through the ECRC. The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $900 million to $1.7 billion.

Storm Cost Recovery

In 2005, the FPSC issued orders authorizing PEF to recover over a two-year period, including interest, costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004, including $232 million beginning August 1, 2005, and an additional $13 million, beginning January 1, 2006.

On August 29, 2006, the FPSC approved a settlement agreement related to PEF's storm cost-recovery docket that would allow PEF to extend its current two-year storm surcharge for an additional 12-month period to replenish its storm reserve. The requested extension, which begins in August 2007, will replenish the existing storm reserve by an estimated additional $130 million. In the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. Intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

Nuclear Cost Recovery

In response to legislation passed by the Florida Legislature in 2006, the FPSC has promulgated rules that will allow PEF to recover prudently incurred siting, preconstruction costs and allowance for funds used during construction (AFUDC) on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. The FPSC approved the new rules on February 13, 2007.

Other Matters

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. The estimated total in-service cost of Hines Unit 4 approved as part of the Determination of Need was $286 million. The unit is planned for commercial operation in December 2007. If the actual cost is less than the original estimate, ratepayers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent, among other things, extraordinary circumstances as found by the FPSC in subsequent proceedings. The current estimate of in-service cost exceeds the initial project estimate by approximately 12 percent to 15 percent due to what we believe to be extraordinary circumstances. Therefore, we believe that disallowance of these costs by the FPSC in subsequent proceedings is not probable. We cannot predict the outcome of this matter.

CAPITAL EXPENDITURES

Total cash from operations provided the funding for our capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2006.

As shown in the table below, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. We anticipate our regulated capital expenditures will increase in 2007 and 2008, primarily due to increased spending on environmental initiatives and current growth and maintenance projects. AFUDC represents the costs of capital funds necessary to finance the construction of new regulated assets.

(in millions)	Actual 2006	Forecasted 2007	2008	2009
Regulated capital expenditures	**$1,423**	$2,250	$2,380	$2,180
Nuclear fuel expenditures	**114**	180	170	210
AFUDC – borrowed funds	**(7)**	(20)	(40)	(40)
Nonregulated capital and other expenditures	**17**	20	10	10
Total	**$1,547**	$2,430	$2,520	$2,360

Regulated capital expenditures for 2007, 2008 and 2009 in the table above include approximately $640 million, $610 million and $220 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2007, 2008 and 2009 include $320 million, $220 million and $50 million, respectively, at PEC and $320 million, $390 million and $170 million, respectively, at PEF. We currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $1.0 billion each at PEC and PEF through 2018, which is the latest compliance target date for current air and water quality regulations. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

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

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2006, we had no outstanding borrowings under our credit facilities. The following table summarizes our RCAs and available capacity at December 31, 2006:

(in millions)	Description	Total	Outstanding	Reserved [a]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$1,130	$ –	$(60)	$1,070
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$ –	$(60)	$1,970

[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, 2006, Progress Energy, Inc. had a total amount of $60 million of letters of credit issued, which were supported by the RCA.

All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities. See Note 12 for additional discussion of our credit facilities.

Our internal financial policy precludes issuing commercial paper in excess of the supporting lines of credit. At December 31, 2006, we had no outstanding commercial paper and a total of $60 million reserved for letters of credit issued, leaving an additional $1.970 billion available for future borrowing under our credit lines. In addition, we have requirements to pay minimal annual commitment fees to maintain our credit facilities. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2006. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2006, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 12.

Progress Energy, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which Progress Energy may issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2006, Progress Energy has the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

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

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2006, PEC and PEF could issue up to $3.333 billion and $4.330 billion, respectively, based on property additions and $1.627 billion and $175 million, respectively, based upon retirements.

CAPITALIZATION RATIOS

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

	2006	2005
Common stock equity	**47.2%**	41.6%
Preferred stock and minority interest	**0.6%**	0.7%
Total debt	**52.2%**	57.7%

CREDIT RATING MATTERS

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

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Stable	Positive	Stable
Corporate credit rating	n/a	BBB	n/a
Senior unsecured debt	Baa2	BBB-	BBB
Commercial paper	P-2	A-2	F-2
PEC			
Outlook	Positive	Positive	Stable
Corporate credit rating	Baa1	BBB	n/a
Commercial paper	P-2	A-2	F-1
Senior secured debt	A3	BBB	A
Senior unsecured debt	Baa1	BBB-	A-
Subordinate debt	Baa2	n/a	n/a
Preferred stock	Baa3	BB+	BBB+
PEF			
Outlook	Stable	Positive	Stable
Corporate credit rating	A3	BBB	n/a
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	BBB	A
Senior unsecured debt	A3	BBB-	A-
Preferred stock	Baa2	BB+	BBB+
FPC Capital I			
Preferred stock [(a)]	Baa2	BB+	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt [(b)]	Baa1	BBB-	n/a

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

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

On November 3, 2006, Fitch upgraded the senior unsecured credit ratings of Progress Energy to BBB from BBB-, PEC to A- from BBB+ and PEF to A- from BBB+. The outlook at each entity was changed to stable. The short-term ratings of PEC and PEF were upgraded to F-1 from F-2. The ratings upgrades were based on our reduced business risk due to nonutility asset sales, the $1.3 billion holding company debt reduction and the successful resolution of the Internal Revenue Service (IRS) audit of the Earthco synthetic fuels facilities (Earthco).

On August 31, 2006, Moody's upgraded Progress Energy's outlook to stable from negative, citing expected holding company debt reduction from asset sale proceeds, successful resolution of the IRS audit of the Earthco synthetic fuels facilities, and lower business risk after divestitures of noncore assets. Moody's also upgraded PEC's outlook to positive from stable, citing PEC's manageable leverage, strong cash flow coverage ratios for its current ratings category, and constructive regulatory environments in North Carolina and South Carolina. PEF's outlook remains stable.

On July 25, 2006, S&P affirmed the corporate credit ratings of BBB at Progress Energy, Inc., PEC and PEF and revised each company's outlook to positive from stable. The outlook revision reflects the progress toward our holding company debt reduction plan and expectations of future financial performance at the BBB+ benchmark levels. S&P also improved Progress Energy's business risk profile to 5 from 6 due to the sales of the DeSoto and Rowan plants and Gas, as well as anticipated cash flow benefits related to the idling of our synthetic fuels facilities.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, we have issued $1.489 billion of guarantees for future financial or performance assurance, including $106 million at PEC and $2 million at PEF. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

The majority of contracts supported by the guarantees contain provisions that trigger guarantee obligations based on downgrade events to below investment grade (below Baa3 or BBB-) by Moody's or S&P for the Parent's senior unsecured debt rating, ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. At December 31, 2006, the Parent's senior unsecured debt rating was Baa2 by Moody's and BBB- by S&P and no guarantee obligations had been triggered. If the guarantee obligations were triggered, the approximate amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for Progress Energy's nonregulated portfolio and power supply agreements, was $596 million at December 31, 2006. While we believe that we would be able to meet this obligation with cash or letters of credit, if we cannot, our financial condition, liquidity and results of operations will be materially and adversely impacted.

At December 31, 2006, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

MARKET RISK AND DERIVATIVES

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms, and actual amounts will likely differ from amounts presented below. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2006, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt [(a)] (See Note 12)	$9,242	$324	$1,277	$1,406	$6,235
Interest payments on long-term debt and interest rate derivatives [(b)]	6,224	545	964	822	3,893
Capital lease obligations (See Note 22B)	589	29	71	68	421
Operating leases (See Note 22B)	428	79	118	59	172
Fuel and purchased power [(c)] [(d)] (See Note 22A)	13,133	2,613	3,447	1,657	5,416
Other purchase obligations [(d)] (See Note 22A)	892	479	299	40	74
Minimum pension funding requirements [(e)]	237	56	95	86	–
Other commitments [(f)(g)]	176	43	26	27	80
Total	$30,921	$4,168	$6,297	$4,165	$16,291

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

(b) Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective at December 31, 2006, and the LIBOR forward curve at December 31, 2006, respectively.

(c) Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.

(d) We have additional contractual obligations associated with our discontinued CCO operations, which are not reflected in this table. They include fuel and purchased power obligations of $11 million for 2007, $1 million for 2008, $2 million each for 2009 through 2011 and $7 million thereafter. These obligations also include other purchase obligations of $15 million each for 2007 through 2009, $13 million each for 2010 and 2011 and $127 million thereafter. We anticipate transferring the obligations under these contracts to a third party as part of our disposition strategy.

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

(f) In 2008, PEC must begin transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

(g) We have certain future commitments related to four synthetic fuels facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 22D).

OTHER MATTERS

SYNTHETIC FUELS TAX CREDITS

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuels facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year may be phased out if annual average market prices for crude oil exceed certain prices. Synthetic fuels are generally not economical to produce and sell absent the credits. In May 2006, we idled production of synthetic fuels at our synthetic fuels facilities. As discussed below in "Impact of Crude Oil Prices," the decision to idle production was based on the high level of oil prices. Based on significantly reduced oil prices combined with current favorable fuel price projections, we resumed limited production at our synthetic fuels facilities in September and October 2006, which continued through the end of 2006. We produced 3.7 million tons of synthetic fuels during 2006.

TAX CREDITS

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K) effective January 1, 2006. The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce more synthetic fuels than we have historically produced, should we choose to do so.

Total Section 29/45K credits generated through December 31, 2006 (including those generated by Florida Progress prior to our acquisition), were approximately $1.9 billion, of which $974 million has been used to offset regular federal income tax liability, $847 million is being carried forward as deferred tax credits and $38 million has been reserved due to the estimated phase-out of tax credits due to high oil prices, as described below.

IMPACT OF CRUDE OIL PRICES

Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for 2007. This possibility is due to a provision of Section 29 that provides that if the Annual Average Price exceeds the Threshold Price, the amount of Section 29/45K tax credits is reduced for that year. Also, if the Annual Average Price exceeds the Phase-out Price, the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits are reduced will depend on where the Annual Average Price falls in that continuum. For example, for 2005, the Threshold Price was $53.20 per barrel and the Phase-out Price was $66.78 per barrel. If the Annual Average Price had been $59.99 per barrel, there would have been a 50 percent reduction in the amount of Section 29 tax credits for that year. Based on the Annual Average Price of $50.26, there was no phase-out of our synthetic fuels tax credits in 2005.

The Department of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the EIA. Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2006 is expected to be published in early April 2007.

We estimate that the 2006 Threshold Price will be approximately $55 per barrel and the Phase-out Price will be approximately $69 per barrel, based on an estimated inflation adjustment for 2006. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $7 lower than the corresponding daily NYMEX prompt month settlement price for light sweet crude oil. Through December 31, 2006, the average daily NYMEX settlement price for light sweet crude oil was $66.25 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, assuming that the $7 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2006, we estimate that the synthetic fuels tax credit amount for 2006 will be reduced by approximately 35 percent. Therefore, we reserved 35 percent or approximately $38 million of the $107 million of tax credits generated during 2006. The final calculations of any reductions in the value of the tax credits will not be determined until April 2007 when final 2006 oil prices are published.

We estimate that the 2007 Threshold Price will be approximately $56 per barrel and the Phase-out Price will be approximately $70 per barrel, based on an estimated inflation adjustment for 2006 and 2007. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $7 lower than the corresponding daily NYMEX prompt month settlement price for light sweet crude oil. As of January 31, 2007, the average NYMEX futures price for light sweet crude oil for calendar year 2007 was $59.50 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price, if oil prices for the rest of 2007 remained at the January 31, 2007, average 2007 futures price level of $59.50 per barrel, we currently estimate that the synthetic fuels tax credit amount for 2007 would not be reduced.

In January 2007 we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices. These contracts will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production and will be marked-to-market with changes in fair value recorded through earnings. Our synthetic fuels production levels for 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2007. We will continue to monitor the environment surrounding synthetic fuels production and will adjust our production as warranted by changing conditions. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

IMPAIRMENT OF SYNTHETIC FUELS AND OTHER RELATED LONG-LIVED ASSETS

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

SALE OF PARTNERSHIP INTEREST

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona, one of our synthetic fuels facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost-recovery basis as the facility produces and sells synthetic fuels and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synthetic fuels production qualifying for Section 29/45K tax credits and the value of such tax credits as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona will be deferred. It is possible that gains will be deferred to subsequent quarters, or to a subsequent calendar year, until there is persuasive evidence that no tax credit phase-out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters in a calendar year or to a subsequent calendar year. In the event that the synthetic fuels tax credits from the Colona facility are reduced, including from an extended idling of our production due to an increase in the price of oil that could limit or eliminate synthetic fuels tax credits, the amount of proceeds realized from the sale could be significantly impacted. At December 31, 2006, a pre-tax gain on monetization of $7 million has been deferred. Based on the current level of oil prices and subject to final adjustments, we expect to recognize this gain in 2007. Beginning with the payment for the second quarter of 2006, the minority interest parties have elected to defer their cash payments in consideration of the idling of the synthetic fuels facilities at that time. In consideration of the resumption of limited synthetic fuels production in the fourth quarter of 2006, the minority interest parties made a partial payment in January 2007.

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

REGULATORY ENVIRONMENT

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and other federal and state agencies common to the utility business. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted to earn, are subject to the approval of these governmental agencies.

PEC and PEF continue to monitor developments impacting retail competition in their respective service territories. Movement toward deregulation throughout the nation has effectively ceased due to numerous factors including, but not limited to, California's experience with retail deregulation. To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate when, or if, any of these states will move to increase retail competition in the electric industry.

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

Issues regarding the timing, creation and structure of transmission organizations are evaluated by the Utilities' regulatory authorities. We cannot predict the outcome of these matters (See Note 7D).

On May 5, 2006, the Florida state legislature passed a comprehensive energy bill, which has been signed by the governor. The legislation creates a new energy council tasked with developing a statewide energy policy, provides incentives to renewable energy sources and fosters the construction of new nuclear power plants, including streamlining the siting of nuclear power plants and related transmission facilities, exempting new nuclear plants from the FPSC bid rule and requiring the FPSC to issue rules authorizing alternative cost-recovery mechanisms for pre-construction costs and construction cost financing. See "Nuclear" below for related FPSC rule issuances. PEF cannot determine at this time how the final rules and regulations resulting from this legislation will impact its operations and financial condition.

Due to the damage electric utility facilities suffered during recent hurricanes, during 2006 the FPSC adopted rules that require Florida's investor-owned electric utilities, including PEF, to strengthen cost effectively, or storm harden, the state's electric infrastructure. Storm-hardening plans are required to be filed and updated every three years for the FPSC's approval. Each plan must address such factors as the effect of extreme wind, flooding and storm surges on electric facilities. The plans must identify critical infrastructure and the respective utilities' deployment strategy for strengthening electric service in their service areas. In addition, state utilities are required to inspect their wooden distribution poles once every eight years. PEF does not believe that compliance with these rules will materially increase PEF's costs due to its pole inspection and vegetation maintenance programs already in effect. Costs to comply with the storm-hardening rules are recoverable through PEF's base rates.

The FPSC has published a proposed rule that specifies what storm costs will be recoverable and whether such recoverable costs would be offset against a utility's storm reserve fund or recoverable through its base rates. The FPSC held a public workshop on February 21, 2007, to discuss the proposed rule with the intent to issue a final rule prior to the 2007 storm season. We cannot predict the outcome of this matter.

On April 26, 2006, PEC submitted a license renewal application with the FERC seeking a 50-year license for its Tillery and Blewett hydroelectric generating plants. The license for these plants currently expires in April 2008 and the requested renewal will allow the plants to continue operations until 2058. PEC and a key group of stakeholders have reached an agreement in principle that supports PEC's relicensing application. The agreement in principle, which has been filed with the FERC, will establish increased water flows from both plants and will protect water supplies for local governments as well as provide enhancements for recreation, water quality and aquatic habits. The remaining phase of the application process will take approximately one year and includes review by the FERC and solicitation of public comment. We cannot predict the outcome of this matter.

In 2004, the FERC issued orders concerning utilities' ability to sell wholesale electricity at market-based rates, including the adoption of two interim screens for assessing an applicant's potential generation market power for determining whether the applicant should be allowed to sell wholesale electricity at market-based rates. The Utilities do not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, PEC filed revisions to its market-based rate tariffs restricting PEC to sales outside of PEC's control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs. We do not anticipate that the operations of the Utilities will be materially impacted by these market-based rates decisions.

LEGAL

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

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 and certain other modifications (See Notes 5 and 22D).

Due to the anticipated growth in our service territories, we estimate that we will require new baseload generation facilities in both Florida and the Carolinas by the middle of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and clean coal technologies. At this time, no definitive decision has been made.

We have announced that we are pursuing development of combined license (COL) applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a plant or plants. On January 23, 2006, we announced that PEC selected a site at the Shearon Harris Nuclear Plant (Harris) to evaluate for possible future nuclear expansion. We currently expect to file the application for the COL for PEC's Harris site in 2007. We have selected for PEC the Westinghouse Electric AP-1000 reactor design as the technology upon which to base the potential application submission. On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion, and PEF expects to file the application for the COL in 2008. We have not selected the reactor design technology upon which to base the PEF potential application submission. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, construction activities could begin as early as 2010, and new plants could be online in late 2016. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 16, 2007, the U.S. Supreme Court declined to hear an appeal of a Ninth Circuit U.S. Court of Appeals' decision in which the Ninth Circuit held that the NRC is required to consider the environmental impacts of terrorist attacks under the National Environmental Policy Act in authorizing an independent spent fuel storage installation. Similar cases, including cases involving operating license renewals, are pending in seven other jurisdictions. The NRC is considering the scope and import of the Ninth Circuit's decision in reviewing its operating license renewal program. The extent and timing of the NRC's application of the case is unclear at this time, and the impact, if any, on PEC's pending Harris operating license renewal application or any future PEC or PEF operating licensing proceedings cannot be predicted at this time.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the IRS provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

In accordance with provisions of Florida's comprehensive energy bill discussed above, in December 2006, the FPSC ordered new rules that would allow investor-owned utilities such as PEF to request partial recovery of the planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on

February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

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.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. Hazardous and solid waste management matters are discussed in detail in Note 21.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated in accordance with accounting principles generally accepted in the United States of America (GAAP). Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates could change and additional losses, which could be material, may be incurred in the future.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which would likely result in increased planned capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxide (NOx), SO_2, carbon dioxide (CO_2) and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment that will be installed pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAMR and CAVR, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

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

Progress Energy

Air and Water Quality Estimated Required Environmental Expenditures (in millions)	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2006
NOx SIP Call	2002-2007	$355	$346
Clean Smokestacks Act	2002-2013	1,000 - 1,400	562
CAIR/CAMR/CAVR	2005-2018	1,100 - 2,000	28
Total air quality		2,455 - 3,755	936
Clean Water Act Section 316(b) [(a)]		–	1
North Carolina Groundwater Standard[(b)]		–	–
Total water quality		–	1
Total air and water quality		$2,455 - $3,755	$937

PEC

Air and Water Quality Estimated Required Environmental Expenditures (in millions)	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2006
NOx SIP Call	2002-2007	$355	$346
Clean Smokestacks Act	2002-2013	1,000 - 1,400	562
CAIR/CAMR/CAVR	2005-2018	200 - 300	1
Total air quality		1,555 - 2,055	909
Clean Water Act Section 316(b) [(a)]		–	–
North Carolina Groundwater Standard[(b)]		–	–
Total water quality		–	–
Total air and water quality		$1,555 - $2,055	$909

PEF

Air and Water Quality Estimated Required Environmental Expenditures (in millions)	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2006
CAIR/CAMR/CAVR	2005-2018	$900 - $1,700	$27
Clean Water Act Section 316(b) [(a)]		–	1
Total air and water quality		$900 - $1,700	$28

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

[(b)] Compliance plans will be determined upon finalization of the changes expected to be proposed to the North Carolina groundwater quality standard for arsenic.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (NSR) requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The outcome of this matter cannot be predicted. However, the EPA has initiated civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms. The U.S. Supreme Court has heard arguments, but not yet issued a ruling, related to an appeal of a decision issued by the U.S. Court of Appeals for the Fourth Circuit, in a case involving an unaffiliated utility, holding that NSR applies to projects that result in an increase in maximum hourly emissions.

On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit set aside the EPA's 2003 NSR equipment replacement rule. The rule would have provided a more uniform definition of routine equipment replacement. The court had earlier set aside a provision in the NSR rule, which had exempted the installation of pollution control projects from review. The Court denied a request by the EPA for a re-hearing regarding this matter on June 30, 2006. These projects are now subject to NSR requirements, adding time and cost to the installation process. On November 27, 2006, the EPA filed a writ of certiorari petition requesting that the U.S. Supreme Court review the U.S. Court of Appeals for the District of Columbia Circuit's ruling that vacated the agency's plant renovation exemption for its NSR rule. The outcome of this matter cannot be predicted.

NOx SIP Call Rule under Section 110 of the Clean Air Act

The NOx SIP Call is an EPA rule that requires 22 states, including North Carolina, South Carolina and Georgia, to further reduce NOx emissions. The NOx SIP Call is not applicable to Florida. Further technical analysis and rulemaking may result in requirements for additional controls at some units. Increased O&M expenses relating to the NOx SIP Call are not expected to be material to our or PEC's results of operations.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. To meet SO_2 emission targets, PEC is installing devices that neutralize sulfur compounds formed during coal combustion (scrubbers) on some of its coal-fired units. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that are then removed. In March 2006, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.1 billion to $1.4 billion at the time of the filing. Currently, the estimate is $1.0 billion to $1.4 billion. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are continuing to evaluate various design, technology, and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. O&M expenses are currently recoverable through base rates.

The Clean Smokestacks Act also freezes the state's utilities' base rates for five years, which ends in 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. For the years ended December 31, 2006, 2005 and 2004, PEC recognized amortization of $140 million, $147 million and $174 million, respectively, and has recognized $535 million in cumulative amortization through December 31, 2006. The remaining amortization requirement of $34 million will be recorded during the one-year period ending December 31, 2007. The NCUC will hold a hearing prior to December 31, 2007, to determine cost-recovery amounts for 2008 and 2009.

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

Pursuant to the Clean Smokestacks Act, PEC entered into an agreement with the state of North Carolina to transfer to the state certain NOx and SO_2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set in the Clean Smokestacks Act. The Clean Smokestacks Act also required the state to undertake a study of mercury and CO_2 emissions in North Carolina. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

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

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires the District of Columbia and 28 states, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the District of Columbia Circuit Court issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. On March 16, 2006, the EPA denied all pending reconsiderations, allowing the challenge to proceed. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAIR, which is very similar to the EPA's model rule. PEF and other Florida utilities are participating in an administrative review of the state-adopted rule. The outcome of these matters cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that sets emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap-and-trade approach to achieving those caps, and a de-listing rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR. The de-listing rule has been challenged by a number of parties; the resolution of the challenges could impact our final compliance plans and costs. On October 21, 2005, the EPA announced a reconsideration of the CAMR. On May 31, 2006, the EPA issued a determination confirming the de-listing. Sixteen states have subsequently petitioned for a review of this determination. The outcome of this matter cannot be predicted.

States were required to adopt mercury rules implementing the CAMR by November 17, 2006, which are subject to review and approval by the EPA. A number of states, including North Carolina, South Carolina and Florida, did not meet the deadline for submission to the EPA. The EPA has indicated it will defer action. At December 31, 2006, of the three states in which the Utilities operate, all had formally proposed mercury regulations. The North Carolina Environmental Management Commission adopted the proposed rule on November 9, 2006, which is subject to final approval by the North Carolina legislature. North Carolina's rule adopts the EPA's cap-and-trade approach and requires the addition of mercury controls by 2018 on certain of PEC's North Carolina units that do not have scrubbers. PEC will have until 2013 to provide the agency detailed plans for the installation of controls at existing plants. South Carolina's rule, which was proposed on October 27, 2006, adopts the EPA's cap-and-trade approach and requires that 25 percent of the mercury allowances allocated to each unit be held in a compliance supplement set-aside pool. Allowances in the set-aside pool may be used by a unit to meet compliance requirements but cannot be traded. South Carolina's rule was adopted on January 11, 2007, and is subject to final approval by the South Carolina legislature. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAMR. The Florida rule adopts the EPA's cap-and-trade approach with changes to the EPA's mercury allowance allocations in the rule's first phase. The outcome of this matter cannot be predicted.

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. Depending on the approach taken by the states, the reductions associated with BART would begin in 2014. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. Plans for compliance with CAIR and CAMR may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, Bartow Unit No. 3, and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted. On December 12, 2006, the U.S. Court of Appeals for the District of Columbia Circuit decided in favor of the EPA in a case brought by the National Parks Conservation Association that alleges the EPA acted improperly by substituting the requirements of CAIR for BART for NOx and SO_2 from electric generating units in areas covered by CAIR.

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

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR, CAMR and CAVR through the ECRC. On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On October 27, 2006, PEF filed supplemental testimony to inform the FPSC that estimated capital costs for the series of compliance alternatives are likely to increase by approximately 25 percent to 30 percent from the estimates filed in March 2006, primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy.

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

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On March 16, 2006, the EPA issued a final response denying the petition. The EPA's rationale for denial is that compliance with CAIR will reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. On June 26, 2006, the North Carolina attorney general filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the agency's final action on the petition. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On December 21, 2005, the EPA announced proposed changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter (PM 2.5) from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA proposed to establish a new 24-hour standard of 70 micrograms per cubic meter for particulate matter that is between 2.5 and 10 microns in diameter (PM 2.5-10). The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter (PM 10). On September 20, 2006, the EPA announced that it is finalizing the PM 2.5 NAAQS as proposed. In addition, the EPA decided not to establish a PM 2.5-10 NAAQS, and it is eliminating the annual PM 10 NAAQS, but the EPA is retaining the 24-hour PM 10 NAAQS. These changes are not expected to result in designation of any additional nonattainment areas in PEC's or PEF's service territories. On December 18, 2006, environmental groups and 13 states filed a joint petition with the U.S. Circuit Court of Appeals for the District of Columbia Circuit arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter. The outcome of this matter cannot be predicted.

Water Quality

1. General

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on the Utilities in the immediate and extended future. The outcome of this matter cannot be predicted.

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

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

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many important provisions of the rule to the EPA. As a result of that decision, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

3. North Carolina Groundwater Standard

On September 14, 2006, the North Carolina Division of Water Quality (NCDWQ) appeared before the North Carolina Environmental Management Commission and recommended the state's groundwater quality standard for arsenic be revised to 0.00002 milligrams/liter. The existing groundwater quality standard for arsenic is 0.05 milligrams/liter. The North Carolina Environmental Management Commission granted approval for NCDWQ staff to publish a notice in the North Carolina Register and schedule public hearings. The rulemaking process will require at least six months before the standard may be changed. Trace amounts of arsenic are commonly present in coal fly ash sluice water, coal pile runoff, flue gas desulphurization byproducts, and other coal combustion byproducts. The specific requirements of the rule as finally adopted and associated costs, if any, cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration favors voluntary programs. There are proposals and ongoing studies at the state and federal levels to address global climate change that would regulate CO_2 and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking voluntary action on this important issue as part of our commitment to environmental stewardship and responsible corporate citizenship.

In a decision issued July 15, 2005, the U.S. Court of Appeals for the District of Columbia Circuit denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation. Following denial of a request for rehearing, the petitioners filed a petition for writ of certiorari with the U.S. Supreme Court, seeking a review of the decision. On June 26, 2006, the U.S. Supreme Court agreed to review the decision. Oral argument was held on November 29, 2006. The outcome of this matter cannot be predicted.

In 2005, we initiated a study to assess the impact of constraints on CO_2 and other air emissions and on March 27, 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

NEW ACCOUNTING STANDARDS

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

PEC

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PEC: "Results of Operations;" "Application of Critical Accounting Policies and Estimates;" "Liquidity and Capital Resources;" "Future Outlook and Other Matters."

The following Management's Discussion and Analysis and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review Item 1A, "Risk Factors" and "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

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

On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P. The amended PEC RCA is still scheduled to expire on June 28, 2010.

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

As discussed above in the Progress Energy "Credit Rating Matters," on November 3, 2006, Fitch upgraded the senior unsecured credit rating of PEC to A- from BBB+ and revised PEC's outlook to stable. The short-term rating of PEC was upgraded to F-1 from F-2. On August 31, 2006, Moody's upgraded PEC's outlook to positive from stable, citing PEC's manageable leverage, strong cash flow coverage ratios for its current ratings category, and constructive regulatory environments in North Carolina and South Carolina. On July 25, 2006, S&P affirmed the corporate credit rating of BBB at PEC and revised PEC's outlook to positive from stable. PEC does not expect these changes to have a material impact on its borrowing costs or overall liquidity.

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

CASH FLOW DISCUSSION

HISTORICAL FOR 2006 AS COMPARED TO 2005 AND 2005 AS COMPARED TO 2004

In 2006, cash provided by operating activities increased when compared to 2005. The $62 million increase in operating cash flow was primarily due to a $136 million increase in the recovery of fuel cost, a $147 million increase from the change in accounts receivable and a $47 million increase from the change in accounts payable. In 2006 and 2005, PEC filed requests with the North Carolina and South Carolina state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. See "Future Liquidity and Capital Resources" under Progress Energy above and Note 7B. The change in accounts receivable was principally driven by the timing of wholesale sales. The change in accounts payable was largely driven by the timing of environmental compliance project payments and other vendor payments. These impacts were partially offset by a $122 million net increase in tax payments in 2006 compared to 2005 and $141 million related to a wholesale customer prepayment in 2005, as discussed below.

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

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

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

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

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2007, 2008 and 2009 are approximately $955 million, $1.160 billion and $1.170 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and for environmental control facilities as discussed above in "Capital Expenditures" under Progress Energy.

PEC expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent. In addition, PEC has $450 million in credit facilities that support the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEC's working capital requirements.

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

CAPITALIZATION RATIOS

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

	2006	2005
Common stock equity	**47.6%**	45.0%
Preferred stock	**0.8%**	0.9%
Total debt	**51.6%**	54.1%

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

GUARANTEES

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

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEC may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

PEC is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms and will likely differ from actual amounts. Further disclosure regarding PEC's contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs. The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2006, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt [a] (See Note 12)	$3,691	$200	$700	$6	$2,785
Interest payments on long-term debt and interest rate derivatives [b]	1,888	200	329	296	1,063
Capital lease obligations (See Note 22B)	24	2	5	5	12
Operating leases (See Note 22B)	269	36	60	31	142
Fuel and purchased power [c] (See Note 22A)	4,358	1,137	1,478	632	1,111
Other purchase obligations (See Note 22A)	172	120	34	6	12
Minimum pension funding requirements [d]	124	34	48	42	–
Other commitments [e]	131	–	26	26	79
Total	$10,657	$1,729	$2,680	$1,044	$5,204

(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 and interest rate derivatives are based on the interest rate effective at December 31, 2006, and the LIBOR forward curve at December 31, 2006, respectively.

(c) Fuel and purchased power commitments represent the majority of PEC's remaining future commitments after its debt obligations. Essentially all of PEC's fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina and South Carolina regulations and therefore do not require separate liquidity support.

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

(e) In 2008, PEC must begin transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

PEF

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PEF: "Results Of Operations;" "Application Of Critical Accounting Policies And Estimates;" "Liquidity And Capital Resources;" "Future Outlook" and "Other Matters."

The following Management's Discussion and Analysis and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review Item 1A, "Risk Factors" and "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

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

On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB- by S&P. The amended PEF RCA is still scheduled to expire on March 28, 2010. On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.

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

As discussed above in the Progress Energy "Credit Rating Matters," on November 3, 2006, Fitch upgraded the senior unsecured credit rating of PEF to A- from BBB+ and revised PEF's outlook to stable. The short-term rating of PEF was upgraded to F-1 from F-2. On August 31, 2006, Moody's reaffirmed PEF's credit rating with a stable outlook. On July 25, 2006, S&P affirmed the corporate credit rating of BBB at PEF and revised PEF's outlook to positive from stable. We do not expect these changes to have a material impact on our borrowing costs or overall liquidity.

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

CASH FLOW DISCUSSION

HISTORICAL FOR 2006 AS COMPARED TO 2005 AND 2005 AS COMPARED TO 2004

Cash from operating activities for 2006 increased when compared with 2005. The $463 million increase in operating cash flow was primarily due to a $577 million improvement from the recovery of fuel costs and $72 million related to recovery of storm restoration costs. In 2005, PEF filed requests with the Florida state commission seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. PEF also received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" under Progress Energy above and Note 7C. These impacts were partially offset by a $94 million increase in inventory levels, primarily related to coal, a $49 million decrease from the change in accounts payable, and a $40 million decrease in derivative premiums received.

Cash from operating activities for 2005 decreased when compared with 2004. The $103 million decrease in operating cash flow was primarily due to a $210 million increase in the under-recovery of fuel costs driven by rising fuel costs and a $32 million increase in working capital needs, partially offset by a $193 million reduction in storm cost spending at PEF in 2005 compared to 2004. The increase in working capital needs for 2005 compared to 2004 was mainly driven by a $50 million increase in the change in receivables, primarily due to increased sales largely driven by rising fuel prices and timing of receipts.

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

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

In planning for its future generation needs, PEF develops a forecast of annual demand for electricity, including a forecast of the level and duration of peak demands during the year. The reserve margin is the difference between a company's net system generating capacity and the maximum demand on the system. In December 1999, the FPSC approved a joint proposal by PEF, Florida Power & Light and Tampa Electric Company to increase the reserve margin to 20 percent from 15 percent. In response, PEF constructed additional generating units at the Hines site. Hines Unit 2 was placed into service in December 2003 and Hines Unit 3 was placed into service in November 2005. PEF is currently constructing Hines Unit 4, which is expected to be completed in December 2007.

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

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2007, 2008 and 2009 are approximately $1.455 billion, $1.350 billion and $1.180 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and add environmental control facilities as discussed above in "Capital Expenditures" under Progress Energy.

PEF expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent. In addition, PEF has $450 million in credit facilities that support the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEF's working capital requirements.

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

CAPITALIZATION RATIOS

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

	2006	2005
Common stock equity	**50.5%**	48.6%
Preferred stock	**0.6%**	0.6%
Total debt	**48.9%**	50.8%

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See 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, 2006.

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEF may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review Item 1A, "Risk Factors" and "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

PROGRESS ENERGY, INC.

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

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

INTEREST RATE RISK

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

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

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

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

The following tables provide information at December 31, 2006 and 2005, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and Florida Progress-obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2007 to 2011 and thereafter and the fair value of the related hedges. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

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

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

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

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

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

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

(a) Excludes $397 million in 2006 classified as long-term debt at December 31, 2005.
(b) FPC Capital I – Quarterly Income Preferred Securities.
(c) Rate is 3-month LIBOR, which was 4.54% at December 31, 2005.
(d) Anticipated 10-year debt issue hedges mature on March 1, 2016, and required mandatory cash settlement on March 1, 2006.

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

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, 2006 and 2005, the fair value of these funds was $1.287 billion and $1.133 billion, respectively, including $735 million and $640 million, respectively, for PEC and $552 million and $493 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

In connection with the acquisition of Florida Progress, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, are based on the net after-tax cash flows the facilities generate. These CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2006 and 2005, the fair value of these CVOs was $32 million and $7 million, respectively. A hypothetical 10 percent decrease in the December 31, 2006, market price would result in a $3 million decrease in the fair value of the CVOs.

COMMODITY PRICE RISK

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

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

As discussed in Note 3, on December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of PVI's remaining CCO physical and commercial assets, and on July 12, 2006, our board of directors approved a plan to divest of Gas. The transaction to sell Gas closed on October 2, 2006. We expect to complete the disposition plan for CCO in 2007.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 Bcf of natural gas would be fulfilled. Therefore, these contracts were no longer treated as cash flow hedges and were dedesignated, and cash flow hedge accounting was discontinued.

At December 31, 2006, derivative assets and derivative liabilities related to CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. At December 31, 2005, derivative assets and derivative liabilities related to Gas and CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. For the years ending December 31, 2006, 2005 and 2004, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ending December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2004, discontinued operations, net of tax includes $10 million in after-tax deferred losses, which were reclassified to earnings due to discontinuance of the related cash flow hedges.

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments, which are not eligible for recovery from ratepayers. At December 31, 2006, as described above, these derivative commodity instruments are included in discontinued operations. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A decrease of 10 percent in the market prices of energy commodities from their December 31, 2006, levels would decrease after-tax earnings of discontinued operations by approximately $55 million. A hypothetical 10 percent increase or decrease in commodity market prices in the near term on our derivative commodity instruments would not have had a material effect on our financial position, results of operations or cash flows at December 31, 2005. As discussed above, certain derivative contracts were dedesignated during 2006 and cash flow hedge accounting was discontinued, which increased the exposure to potential earnings impacts in the near term from changes in commodity market prices.

The above analysis of our derivative commodity instruments used for hedging purposes does not include the potential favorable impact of the same hypothetical price movement on the physical purchases of natural gas and power to which the hedges relate. Additionally, our derivative commodity portfolio is managed to complement the physical transaction portfolio, reducing overall risk within set limits. Therefore, the potential impact to earnings of discontinued operations from a hypothetical 10 percent adverse change in commodity market prices would be offset by a favorable impact on the underlying hedged physical transactions, assuming the derivative commodity positions are not closed out in advance of their expected term, continue to function effectively as hedges of the underlying risk, and the anticipated underlying transactions settle, as applicable. If any of these assumptions ceases to be true, a loss on the derivative instruments may occur.

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

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our or the Utilities' results of operations during the years ended December 31, 2006, 2005 and 2004. Excluding $107 million of derivative assets, which are included in assets of discontinued operations on the Consolidated Balance Sheet and $31 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2006, we did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment at PEF, as discussed below. Our discontinued operations did not have material outstanding positions in such contracts at December 31, 2005.

PEC did not have material outstanding positions in such contracts at December 31, 2006 and 2005. PEF did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment, as discussed below.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2006, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits, an $87 million short-term derivative liability position included in other current liabilities and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $49 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a NYMEX basis. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts will be marked-to-market with changes in fair value recorded through earnings from synthetic fuels production.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2006, 2005 and 2004.

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

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Fair value of assets	**\$2**	\$7	**\$2**	\$7	**\$–**	\$–
Fair value of liabilities	**–**	(4)	**–**	(4)	**–**	–
Fair value, net	**\$2**	\$3	**\$2**	\$3	**\$–**	\$–

Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. Excluded from the table above are \$163 million of derivative assets, which are included in assets of discontinued operations, and \$54 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2005.

At December 31, 2006, the amount recorded in our, PEC's or PEF's accumulated other comprehensive income (AOCI) related to commodity cash flow hedges was not material. At December 31, 2005, we had \$69 million of after-tax deferred income and PEC had \$2 million of after-tax deferred income recorded in AOCI related to commodity cash flow hedges. PEF had no amount recorded in AOCI related to commodity cash flow hedges at December 31, 2006 or 2005.

PEC

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

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

INTEREST RATE RISK

The following tables provide information at December 31, 2006 and 2005, about PEC's interest rate risk sensitive instruments:

December 31, 2006 **(dollars in millions)**	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**	**Fair Value December 31, 2006**
Fixed-rate long-term debt	**\$200**	**\$300**	**\$400**	**\$6**	**–**	**\$2,165**	**\$3,071**	**\$3,112**
Average interest rate	**6.80%**	**6.65%**	**5.95%**	**6.30%**	**–**	**5.79%**	**5.96%**	
Variable-rate long-term debt	**–**	**–**	**–**	**–**	**–**	**\$620**	**\$620**	**\$620**
Average interest rate	**–**	**–**	**–**	**–**	**–**	**3.61%**	**3.61%**	
Interest rate forward contracts[a]	**\$50**	**–**	**–**	**–**	**–**	**–**	**\$50**	**\$(1)**
Average pay rate	**5.61%**	**–**	**–**	**–**	**–**	**–**	**5.61%**	
Average receive rate	**[b]**	**–**	**–**	**–**	**–**	**–**	**[b]**	

[a] Anticipated 10-year debt issue hedge matures on October 1, 2017, and requires mandatory cash settlement on October 1, 2007.

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

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

COMMODITY PRICE RISK

PEC is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. PEC's exposure to these fluctuations is significantly limited by cost-based regulation. Each state commission allows electric utilities to recover certain of these costs through various cost-recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. PEC may engage in limited economic hedging activity using natural gas and electricity financial instruments. See "Commodity Price Risk" discussion under Progress Energy above and Note 17 for additional information with regard to PEC's commodity contracts and use of derivative financial instruments.

PEF

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

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

INTEREST RATE RISK

The following tables provide information at December 31, 2006 and 2005, about PEF's interest rate risk sensitive instruments:

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

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

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

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

COMMODITY PRICE RISK

PEF is exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. PEF's exposure to these fluctuations is significantly limited by its cost-based regulation. The FPSC allows PEF to recover certain fuel and purchased power costs to the extent the FPSC determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. See "Commodity Price Risk" discussion under Progress Energy above and Note 17 for additional information with regard to PEF's commodity contracts and use of derivative financial instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

Registrant	Applicable Notes
PEC	1, 2, 5 through 10, 12 through 14, 16 through 22 and 24
PEF	1 through 3, 5 through 10, 12 through 14, 16 through 22 and 24

Consolidated Financial Statement Schedules for the Years Ended December 31, 2006, 2005 and 2004:

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 158, and in 2005 the Company adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting at December 31, 2006, 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, 2007, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of INCOME

(in millions except per share data) Years ended December 31	2006	2005	2004
Operating revenues			
Electric	$8,722	$7,945	$7,153
Diversified business	848	1,223	900
Total operating revenues	9,570	9,168	8,053
Operating expenses			
Utility			
Fuel used in electric generation	3,008	2,359	2,011
Purchased power	1,100	1,048	868
Operation and maintenance	1,583	1,770	1,475
Depreciation and amortization	1,009	922	878
Taxes other than on income	500	460	425
Other	(3)	(37)	(13)
Diversified business			
Cost of sales	898	1,353	992
Depreciation and amortization	23	41	41
Impairments of assets	91	–	–
Gain on the sales of assets	(4)	(30)	(8)
Other	56	62	112
Total operating expenses	8,261	7,948	6,781
Operating income	1,309	1,220	1,272
Other income (expense)			
Interest income	61	16	11
Other, net	(18)	(7)	4
Total other income	43	9	15
Interest charges			
Net interest charges	632	587	572
Allowance for borrowed funds used during construction	(7)	(13)	(6)
Total interest charges, net	625	574	566
Income from continuing operations before income tax and minority interest	727	655	721
Income tax expense (benefit)	204	(37)	67
Income from continuing operations before minority interest	523	692	654
Minority interest in subsidiaries' (income) loss, net of tax	(9)	29	19
Income from continuing operations	514	721	673
Discontinued operations, net of tax	57	(25)	86
Cumulative effect of change in accounting principle, net of tax	–	1	–
Net income	$571	$697	$759
Average common shares outstanding – basic	250	247	242
Basic earnings per common share			
Income from continuing operations	$2.05	$2.92	$2.78
Discontinued operations, net of tax	0.23	(0.10)	0.35
Net income	$2.28	$2.82	$3.13
Diluted earnings per common share			
Income from continuing operations	$2.05	$2.92	$2.77
Discontinued operations, net of tax	0.23	(0.10)	0.35
Net income	$2.28	$2.82	$3.12
Dividends declared per common share	$2.43	$2.38	$2.32

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

PROGRESS ENERGY, INC.
CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2006	2005
ASSETS		
Utility plant		
Utility plant in service	**$23,743**	$22,940
Accumulated depreciation	**(10,064)**	(9,602)
Utility plant in service, net	**13,679**	13,338
Held for future use	**10**	12
Construction work in progress	**1,289**	813
Nuclear fuel, net of amortization	**267**	279
Total utility plant, net	**15,245**	14,442
Current assets		
Cash and cash equivalents	**265**	605
Short-term investments	**71**	191
Receivables, net	**930**	997
Inventory	**969**	823
Deferred fuel cost	**196**	602
Deferred income taxes	**159**	37
Assets of discontinued operations	**887**	2,566
Prepayments and other current assets	**108**	186
Total current assets	**3,585**	6,007
Deferred debits and other assets		
Regulatory assets	**1,231**	854
Nuclear decommissioning trust funds	**1,287**	1,133
Diversified business property, net	**31**	78
Miscellaneous other property and investments	**456**	476
Goodwill	**3,655**	3,655
Intangibles, net	**–**	59
Other assets and deferred debits	**211**	358
Total deferred debits and other assets	**6,871**	6,613
Total assets	**$25,701**	$27,062
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 256 and 252 million shares issued and outstanding, respectively	**$5,791**	$5,571
Unearned ESOP shares (2 and 3 million shares, respectively)	**(50)**	(63)
Accumulated other comprehensive loss	**(49)**	(104)
Retained earnings	**2,594**	2,634
Total common stock equity	**8,286**	8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93
Minority interest	**10**	36
Long-term debt, affiliate	**271**	270
Long-term debt, net	**8,564**	10,176
Total capitalization	**17,224**	18,613
Current liabilities		
Current portion of long-term debt	**324**	513
Accounts payable	**712**	601
Interest accrued	**171**	208
Dividends declared	**156**	152
Short-term debt	**–**	175
Customer deposits	**227**	200
Liabilities of discontinued operations	**189**	542
Income taxes accrued	**284**	116
Other current liabilities	**755**	542
Total current liabilities	**2,818**	3,049
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**306**	198
Accumulated deferred investment tax credits	**151**	163
Regulatory liabilities	**2,543**	2,527
Asset retirement obligations	**1,306**	1,242
Accrued pension and other benefits	**957**	865
Other liabilities and deferred credits	**396**	405
Total deferred credits and other liabilities	**5,659**	5,400
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$25,701**	$27,062

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

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	**2006**	2005	2004
Operating activities			
Net income	**$571**	$697	$759
Adjustments to reconcile net income to net cash provided by operating activities			
(Income) loss from discontinued operations, net of tax	**(57)**	25	(86)
Gain on sales of operating assets	**(7)**	(67)	(21)
Impairment of long-lived assets and investments	**92**	–	–
Charges for voluntary enhanced retirement program	**–**	159	–
Depreciation and amortization	**1,119**	1,083	1,037
Deferred income taxes	**(72)**	(379)	(118)
Investment tax credit	**(12)**	(13)	(14)
Deferred fuel cost (credit)	**396**	(317)	(19)
Other adjustments to net income	**85**	157	113
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**47**	(154)	16
Inventory	**(171)**	(136)	(84)
Prepayments and other current assets	**(71)**	(78)	19
Accounts payable	**46**	103	(30)
Other current liabilities	**(70)**	109	67
Regulatory assets and liabilities	**11**	(74)	(234)
Other liabilities and deferred credits	**(44)**	101	(60)
Other assets and deferred debits	**49**	(41)	64
Net cash provided by operating activities	**1,912**	1,175	1,409
Investing activities			
Gross utility property additions	**(1,423)**	(1,080)	(998)
Diversified business property additions	**(2)**	(6)	(6)
Nuclear fuel additions	**(114)**	(126)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**1,654**	475	372
Purchases of available-for-sale securities and other investments	**(2,452)**	(3,985)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	**2,631**	3,845	3,248
Other investing activities	**(23)**	(37)	(30)
Net cash provided (used) by investing activities	**271**	(914)	(649)
Financing activities			
Issuance of common stock	**185**	208	73
Proceeds from issuance of long-term debt, net	**397**	1,642	421
Net (decrease) increase in short-term debt	**(175)**	(509)	680
Retirement of long-term debt	**(2,200)**	(564)	(1,112)
Dividends paid on common stock	**(607)**	(582)	(558)
Cash distributions to minority interests of consolidated subsidiary	**(79)**	–	–
Other financing activities	**11**	34	11
Net cash (used) provided by financing activities	**(2,468)**	229	(485)
Cash provided (used) by discontinued operations			
Operating activities	**86**	294	191
Investing activities	**(141)**	(232)	(199)
Financing activities	**–**	(2)	(246)
Net (decrease) increase in cash and cash equivalents	**(340)**	550	21
Cash and cash equivalents at beginning of year	**605**	55	34
Cash and cash equivalents at end of year	**$265**	$605	$55
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$692**	$643	$639
income taxes (net of refunds)	**$311**	$168	$189

Noncash activities

- In addition to normal and recurring accruals for capital additions, Progress Energy Florida recorded purchases and construction costs for utility plant and equipment and a corresponding liability for $47 million related to additions at an electric generation facility in 2006. Actual cash expenditures will not occur until 2007.
- In 2005, Progress Energy Florida entered into a capital lease agreement for a building that was completed in 2006, at which point Progress Energy Florida recorded a capital lease asset and obligation for $54 million.

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

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2003	246	$5,270	$(17)	$(89)	$(50)	$2,330	$7,444
Net income		–	–	–	–	759	759
Other comprehensive loss		–	–	–	(114)	–	(114)
Comprehensive income							645
Issuance of shares	1	62	–	–	–	–	62
Stock options exercised		18	–	–	–	–	18
Purchase of restricted stock		–	(7)	–	–	–	(7)
Restricted stock expense recognition		–	7	–	–	–	7
Cancellation of restricted shares		(4)	4	–	–	–	–
Allocation of ESOP shares		14	–	13	–	–	27
Dividends ($2.32 per share)		–	–	–	–	(563)	(563)
Balance, December 31, 2004	247	5,360	(13)	(76)	(164)	2,526	7,633
Net income		–	–	–	–	697	697
Other comprehensive income		–	–	–	60	–	60
Comprehensive income							757
Issuance of shares	5	199	–	–	–	–	199
Presentation reclassification –SFAS No. 123R adoption		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Restricted stock expense recognition		3	–	–	–	–	3
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		10	–	–	–	–	10
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	**252**	**5,571**	–	**(63)**	**(104)**	**2,634**	**8,038**
Net income		–	–	–	–	**571**	**571**
Other comprehensive loss		–	–	–	**(18)**	–	**(18)**
Comprehensive income							**553**
Adjustment to initially apply SFAS No. 158, net of tax		–	–	–	**73**	–	**73**
Issuance of shares	**4**	**70**	–	–	–	–	**70**
Stock options exercised		**115**	–	–	–	–	**115**
Purchase of restricted stock		**(8)**	–	–	–	–	**(8)**
Restricted stock expense recognition		**5**	–	–	–	–	**5**
Allocation of ESOP shares		**13**	–	**13**	–	–	**26**
Stock-based compensation expense		**25**	–	–	–	–	**25**
Dividends ($2.43 per share)		–	–	–	–	**(611)**	**(611)**
Balance, December 31, 2006	**256**	**$5,791**	**$–**	**$(50)**	**$(49)**	**$2,594**	**$8,286**

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2006**	2005	2004
Net income	**$571**	$697	$759
Other comprehensive (loss) income			
Reclassification adjustment for amounts included in net income:			
Cash flow hedges (net of tax benefit (expense) of $28, $(26) and $(16), respectively)	**(46)**	46	26
Foreign currency translation adjustments included in discontinued operations	–	(6)	–
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	–	1	–
Changes in net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $16, ($26) and $10, respectively)	**(23)**	37	(18)
Reclassification of minimum pension liability to regulatory assets (net of tax expense of $2)	–	–	4
Minimum pension liability adjustment (net of tax (expense) benefit of $(30), $22 and $78, respectively)	**48**	(19)	(130)
Foreign currency translation and other (net of tax expense of $-, $1 and $-, respectively)	**3**	1	4
Other comprehensive (loss) income	**(18)**	60	(114)
Comprehensive income	**$553**	$757	$645

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) at December 31, 2006 and 2005, and the related consolidated statements of income, changes in common stock equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of PEC's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. PEC is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of PEC's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PEC at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2006 PEC adopted Statement of Financial Accounting Standards No. 158, and in 2005 PEC adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

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

CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	**2006**	2005	2004
Operating revenues			
Electric	**$4,085**	$3,990	$3,628
Diversified business	**1**	1	1
Total operating revenues	**4,086**	3,991	3,629
Operating expenses			
Fuel used in electric generation	**1,173**	1,036	836
Purchased power	**334**	354	301
Operation and maintenance	**930**	941	871
Depreciation and amortization	**571**	561	570
Taxes other than on income	**191**	178	173
Other	**(1)**	(11)	(12)
Diversified business	**1**	1	1
Total operating expenses	**3,199**	3,060	2,740
Operating income	**887**	931	889
Other income (expense)			
Interest income	**25**	8	4
Other, net	**25**	(15)	(1)
Total other income (expense)	**50**	(7)	3
Interest charges			
Interest charges	**217**	197	195
Allowance for borrowed funds used during construction	**(2)**	(5)	(3)
Total interest charges, net	**215**	192	192
Income before income taxes	**722**	732	700
Income tax expense	**265**	239	239
Net income	**457**	493	461
Preferred stock dividend requirement	**3**	3	3
Earnings for common stock	**$454**	$490	$458

See Notes to PEC Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2006	2005
ASSETS		
Utility plant		
Utility plant in service	**$14,356**	$13,994
Accumulated depreciation	**(6,408)**	(6,120)
Utility plant in service, net	**7,948**	7,874
Held for future use	**3**	3
Construction work in progress	**617**	399
Nuclear fuel, net of amortization	**209**	203
Total utility plant, net	**8,777**	8,479
Current assets		
Cash and cash equivalents	**71**	125
Short-term investments	**50**	191
Receivables, net	**473**	518
Receivables from affiliated companies	**27**	24
Note receivable from affiliated company	**24**	–
Inventory	**497**	451
Deferred fuel cost	**196**	261
Prepayments and other current assets	**45**	20
Total current assets	**1,383**	1,590
Deferred debits and other assets		
Regulatory assets	**777**	421
Nuclear decommissioning trust funds	**735**	640
Miscellaneous other property and investments	**193**	188
Other assets and deferred debits	**155**	184
Total deferred debits and other assets	**1,860**	1,433
Total assets	**$12,020**	$11,502
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, authorized 200 million shares, 160 million shares issued and outstanding at December 31	**$2,010**	$1,981
Unearned ESOP common stock	**(50)**	(63)
Accumulated other comprehensive loss	**(1)**	(120)
Retained earnings	**1,431**	1,320
Total common stock equity	**3,390**	3,118
Preferred stock – not subject to mandatory redemption	**59**	59
Long-term debt, net	**3,470**	3,667
Total capitalization	**6,919**	6,844
Current liabilities		
Current portion of long-term debt	**200**	–
Accounts payable	**310**	247
Payables to affiliated companies	**108**	73
Notes payable to affiliated companies	**–**	11
Interest accrued	**69**	73
Short-term debt	**–**	73
Customer deposits	**59**	52
Income taxes accrued	**68**	100
Current portion of unearned revenue	**71**	70
Other current liabilities	**154**	185
Total current liabilities	**1,039**	884
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**909**	814
Accumulated deferred investment tax credits	**128**	133
Regulatory liabilities	**1,320**	1,196
Asset retirement obligations	**1,004**	949
Accrued pension and other benefits	**581**	511
Other liabilities and deferred credits	**120**	171
Total deferred credits and other liabilities	**4,062**	3,774
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$12,020**	$11,502

See Notes to PEC Consolidated Financial Statements.

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

(in millions) Years Ended December 31	**2006**	2005	2004
Operating activities			
Net income	**$457**	$493	$461
Adjustments to reconcile net income to net cash provided by operating activities			
Charges for voluntary enhanced retirement program	**–**	42	–
Depreciation and amortization	**656**	644	658
Deferred income taxes and investment tax credits, net	**(59)**	(150)	(26)
Deferred fuel credit	**(8)**	(144)	(56)
Other adjustments to net income	**(23)**	69	50
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**36**	(111)	(4)
Receivables from affiliated companies	**9**	11	15
Inventory	**(69)**	(91)	(22)
Prepayments and other current assets	**10**	9	17
Accounts payable	**56**	9	34
Payables to affiliated companies	**32**	(13)	(53)
Other current liabilities	**(40)**	239	11
Regulatory assets and liabilities	**1**	2	9
Other liabilities and deferred credits	**(2)**	42	(63)
Other assets and deferred debits	**38**	(19)	45
Net cash provided by operating activities	**1,094**	1,032	1,076
Investing activities			
Gross utility property additions	**(705)**	(603)	(519)
Proceeds from sales of assets	**5**	14	25
Nuclear fuel additions	**(102)**	(79)	(101)
Purchases of available-for-sale securities and other investments	**(896)**	(1,832)	(2,479)
Proceeds from sales of available-for-sale securities and other investments	**1,006**	1,692	2,592
Other investing activities	**(30)**	(3)	(3)
Net cash used in investing activities	**(722)**	(811)	(485)
Financing activities			
Proceeds from issuance of long-term debt, net	**–**	898	–
Net (decrease) increase in short-term debt	**(73)**	(148)	217
Changes in advances from affiliates	**(11)**	(105)	91
Retirement of long-term debt	**–**	(300)	(339)
Dividends paid to parent	**(339)**	(457)	(551)
Dividends paid on preferred stock	**(3)**	(3)	(3)
Other financing activities	**–**	1	–
Net cash used in financing activities	**(426)**	(114)	(585)
Net (decrease) increase in cash and cash equivalents	**(54)**	107	6
Cash and cash equivalents at beginning of year	**125**	18	12
Cash and cash equivalents at end of year	**$71**	$125	$18
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$210**	$187	$185
income taxes (net of refunds)	**$347**	$222	$286

See Notes to PEC Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2003	160	$1,953	$(89)	$(7)	$1,380	$3,237
Net income		–	–	–	461	461
Other comprehensive loss		–	–	(107)	–	(107)
Comprehensive income						354
Allocation of ESOP shares		22	13	–	–	35
Preferred stock dividends at stated rates		–	–	–	(3)	(3)
Dividends paid to parent		–	–	–	(551)	(551)
Balance, December 31, 2004	160	1,975	(76)	(114)	1,287	3,072
Net income		–	–	–	493	493
Other comprehensive loss		–	–	(6)	–	(6)
Comprehensive income						487
Stock-based compensation expense		3	–	–	–	3
Allocation of ESOP shares		20	13	–	–	33
Noncash dividend to parent		(17)	–	–	–	(17)
Preferred stock dividends at stated rates		–	–	–	(3)	(3)
Dividends paid to parent		–	–	–	(457)	(457)
Balance, December 31, 2005	**160**	**1,981**	**(63)**	**(120)**	**1,320**	**3,118**
Net income		–	–	–	**457**	**457**
Other comprehensive income		–	–	**36**	–	**36**
Comprehensive income						**493**
Adjustment to initially apply SFAS No. 158, net of tax		–	–	**83**	–	**83**
Stock-based compensation expense		**10**	–	–	–	**10**
Allocation of ESOP shares		**19**	**13**	–	–	**32**
Preferred stock dividends at stated rates		–	–	–	**(3)**	**(3)**
Dividends paid to parent		–	–	–	**(339)**	**(339)**
Tax benefit dividend		–	–	–	**(4)**	**(4)**
Balance, December 31, 2006	**160**	**$2,010**	**$(50)**	**$(1)**	**$1,431**	**$3,390**

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

CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2006**	2005	2004
Net income	**$457**	$493	$461
Other comprehensive (loss) income			
Changes in net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $2, ($2), and $1, respectively)	**(2)**	3	(1)
Reclassification adjustment for amounts included in net income (net of tax expense of $-)	–	1	–
Minimum pension liability adjustment (net of tax (expense) benefit of $(23), $7, and $68, respectively)	**36**	(12)	(106)
Other (net of tax benefit (expense) of $1, $(1), and $-, respectively)	**2**	2	–
Other comprehensive income (loss)	**36**	(6)	(107)
Comprehensive income	**$493**	$487	$354

See Notes to PEC Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) at December 31, 2006 and 2005, and the related statements of income, changes in common stock equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of PEF's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. PEF is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of PEF's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of PEF at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 PEF adopted Statement of Financial Accounting Standards No. 158, and in 2005 PEF adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

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

STATEMENTS of INCOME

(in millions) Years ended December 31	**2006**	2005	2004
Operating revenues	**$4,639**	$3,955	$3,525
Operating expenses			
Fuel used in electric generation	**1,835**	1,323	1,175
Purchased power	**766**	694	567
Operation and maintenance	**684**	852	630
Depreciation and amortization	**404**	334	281
Taxes other than on income	**309**	279	254
Other	**(2)**	(26)	(2)
Total operating expenses	**3,996**	3,456	2,905
Operating income	**643**	499	620
Other income			
Interest income	**15**	1	–
Other, net	**13**	7	3
Total other income	**28**	8	3
Interest charges			
Interest charges	**155**	134	117
Allowance for borrowed funds used during construction	**(5)**	(8)	(3)
Total interest charges, net	**150**	126	114
Income before income taxes	**521**	381	509
Income tax expense	**193**	121	174
Net income	**328**	260	335
Preferred stock dividend requirement	**2**	2	2
Earnings for common stock	**$326**	$258	$333

See Notes to PEF Financial Statements.

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

BALANCE SHEETS

(in millions) December 31	**2006**	2005
ASSETS		
Utility plant		
Utility plant in service	**$9,202**	$8,756
Accumulated depreciation	**(3,602)**	(3,434)
Utility plant in service, net	**5,600**	5,322
Held for future use	**7**	9
Construction work in progress	**672**	414
Nuclear fuel, net of amortization	**58**	76
Total utility plant, net	**6,337**	5,821
Current assets		
Cash and cash equivalents	**23**	218
Receivables, net	**340**	331
Receivables from affiliated companies	**11**	11
Deferred income taxes	**86**	12
Inventory	**436**	311
Deferred fuel cost	**–**	341
Income taxes receivable	**47**	–
Derivative assets	**–**	77
Prepayments and other current assets	**62**	23
Total current assets	**1,005**	1,324
Deferred debits and other assets		
Regulatory assets	**454**	351
Nuclear decommissioning trust funds	**552**	493
Miscellaneous other property and investments	**45**	47
Prepaid pension cost	**174**	200
Other assets and deferred debits	**26**	82
Total deferred debits and other assets	**1,251**	1,173
Total assets	**$8,593**	$8,318
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$1,100**	$1,097
Accumulated other comprehensive loss	**(1)**	–
Retained earnings	**1,588**	1,498
Total common stock equity	**2,687**	2,595
Preferred stock – not subject to mandatory redemption	**34**	34
Long-term debt, net	**2,468**	2,554
Total capitalization	**5,189**	5,183
Current liabilities		
Current portion of long-term debt	**89**	48
Accounts payable	**292**	237
Payables to affiliated companies	**116**	101
Notes payable to affiliated companies	**47**	13
Short-term debt	**–**	102
Customer deposits	**168**	148
Interest accrued	**38**	42
Derivative liabilities	**89**	–
Current regulatory liabilities	**76**	10
Other current liabilities	**89**	91
Total current liabilities	**1,004**	792
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**466**	433
Accumulated deferred investment tax credits	**23**	30
Regulatory liabilities	**1,091**	1,189
Asset retirement obligations	**299**	290
Accrued pension and other benefits	**332**	257
Other liabilities and deferred credits	**189**	144
Total deferred credits and other liabilities	**2,400**	2,343
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	**$8,593**	$8,318

See Notes to PEF Financial Statements.

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

(in millions) Years ended December 31	**2006**	2005	2004
Operating activities			
Net income	**$328**	$260	$335
Adjustments to reconcile net income to net cash provided by operating activities			
Gain on sales of operating assets	**(2)**	(26)	(1)
Charges for voluntary enhanced retirement program	**–**	92	–
Depreciation and amortization	**433**	367	310
Deferred income taxes and investment tax credits, net	**(48)**	(50)	110
Deferred fuel cost (credit)	**404**	(173)	37
Other adjustments to net income	**21**	45	(13)
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(23)**	(70)	(20)
Receivables from affiliated companies	**–**	4	(8)
Inventory	**(128)**	(34)	(36)
Prepayments and other current assets	**(37)**	(22)	2
Accounts payable	**3**	52	13
Payables to affiliated companies	**15**	21	14
Other current liabilities	**(35)**	(7)	11
Regulatory assets and liabilities	**10**	(76)	(243)
Other liabilities and deferred credits	**(52)**	50	14
Other assets and deferred debits	**4**	(3)	8
Net cash provided by operating activities	**893**	430	533
Investing activities			
Gross utility property additions	**(727)**	(496)	(492)
Nuclear fuel additions	**(12)**	(47)	–
Proceeds from sales of assets	**3**	43	–
Purchases of available-for-sale securities and other investments	**(625)**	(405)	(569)
Proceeds from sales of available-for-sale securities and other investments	**625**	405	569
Other investing activities	**1**	(6)	(4)
Net cash used in investing activities	**(735)**	(506)	(496)
Financing activities			
Proceeds from issuance of long-term debt, net	**–**	744	56
Net (decrease) increase in short-term debt	**(102)**	(191)	293
Retirement of long-term debt	**(48)**	(102)	(43)
Changes in advances from affiliates	**34**	(165)	(185)
Dividends paid to parent	**(234)**	–	(155)
Dividends paid on preferred stock	**(2)**	(2)	(2)
Other financing activities	**(1)**	(2)	1
Net cash (used) provided by financing activities	**(353)**	282	(35)
Net (decrease) increase in cash and cash equivalents	**(195)**	206	2
Cash and cash equivalents at beginning of year	**218**	12	10
Cash and cash equivalents at end of year	**$23**	$218	$12
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$152**	$131	$118
income taxes (net of refunds)	**$296**	$185	$57

Noncash activities

- In addition to normal and recurring accruals for capital additions, Progress Energy Florida recorded purchases and construction costs for utility plant and equipment and a corresponding liability for $47 million related to additions at an electric generation facility in 2006. Actual cash expenditures will not occur until 2007.
- In 2005, Progress Energy Florida entered into a capital lease agreement for a building that was completed in 2006, at which point Progress Energy Florida recorded a capital lease asset and obligation for $54 million.

See Notes to PEF Financial Statements.

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

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2003	100	$1,081	$(4)	$1,062	$2,139
Net income		–	–	335	335
Other comprehensive income		–	4	–	4
Comprehensive income					339
Preferred stock dividends at stated rates		–	–	(2)	(2)
Dividends paid to parent		–	–	(155)	(155)
Balance, December 31, 2004	100	1,081	–	1,240	2,321
Net income		–	–	260	260
Comprehensive income					260
Stock-based compensation expense		1	–	–	1
Noncash contribution from parent		15	–	–	15
Preferred stock dividends at stated rates		–	–	(2)	(2)
Balance, December 31, 2005	**100**	**1,097**	**–**	**1,498**	**2,595**
Net income		–	–	**328**	**328**
Other comprehensive loss		–	**(1)**	–	**(1)**
Comprehensive income					**327**
Stock-based compensation expense		**3**	–	–	**3**
Preferred stock dividends at stated rates		–	–	**(2)**	**(2)**
Dividends paid to parent		–	–	**(234)**	**(234)**
Tax benefit dividend		–	–	**(2)**	**(2)**
Balance, December 31, 2006	**100**	**$1,100**	**$(1)**	**$1,588**	**$2,687**

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

(in millions) Years ended December 31	**2006**	2005	2004
Net income	**$328**	$260	$335
Other comprehensive (loss) income			
Changes in net unrealized losses on cash flow hedges (net of tax benefit of $1)	**(1)**	–	–
Reclassification of minimum pension liability to regulatory assets (net of tax expense of $2)	**–**	–	4
Other comprehensive (loss) income	**(1)**	–	4
Comprehensive income	**$327**	$260	$339

See Notes to PEF Financial Statements.

COMBINED NOTES TO FINANCIAL STATEMENTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc.

The Parent is a holding company headquartered in Raleigh, N.C. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005). Prior to February 8, 2006, the Parent was subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA 1935), as amended.

Our reportable segments are: PEC, PEF and Coal and Synthetic Fuels. Our PEC and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity. Our Coal and Synthetic Fuels segment is primarily engaged in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (the Code), the operation of synthetic fuels facilities for third parties, and coal terminal services. Our Corporate and Other segment (Corporate and Other) is comprised of the activities of the Parent and Progress Energy Service Company (PESC) as well as nonregulated businesses, which do not separately meet the disclosure requirements as a business segment.

See Note 19 for further information about our segments.

PEC

PEC is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. PEC's subsidiaries are involved in insignificant nonregulated business activities. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in west central Florida. PEF is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), the NRC and the FERC.

B. Basis of Presentation

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

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

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

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

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

Certain amounts for 2005 and 2004 have been reclassified to conform to the 2006 presentation.

C. Consolidation of Variable Interest Entities

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

Progress Energy

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2006, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $7 million, which represents our net remaining investment in the entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. At December 31, 2006, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheet.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $45 million, $44 million and $42 million in 2006, 2005 and 2004, respectively. The generation capacity of the entity's power plant is approximately 835 megawatts (MW). PEC has requested the necessary information to determine if the power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in 20 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2006, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $21 million, which primarily represents its net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF

PEF has interests in three variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2006, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $57 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

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

(in millions)	**2006**	2005	2004
Progress Energy	**$293**	$258	$240
PEC	**94**	91	89
PEF	**199**	167	151

STOCK-BASED COMPENSATION

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

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered. The repeal of PUHCA 1935 and subsequent regulation by the FERC did not change our current intercompany services.

UTILITY PLANT

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

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

ASSET RETIREMENT OBLIGATIONS

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

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

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

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

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year.

CASH AND CASH EQUIVALENTS

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

INVENTORY

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

REGULATORY ASSETS AND LIABILITIES

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

DIVERSIFIED BUSINESS PROPERTY

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

We use the full-cost method to account for our oil and gas properties. Under the full-cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized. These capitalized costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future cost to develop proved reserves. Except for costs of unproved properties and major development projects in progress, all costs are amortized using the units-of-production method on a country-by-country basis over the life of our proved reserves. Accordingly, all property acquisition, exploration, and development costs of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals, are capitalized as incurred, including internal costs directly attributable to such activities. Related interest expense incurred during property development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred. In accordance with Rule 4-10 of Regulation S-X, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless certain significance tests are met. During 2006, we sold our natural gas drilling and production business, and we met the significance tests necessary to recognize a gain on the transaction (See Note 3B).

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC and PEF in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provides an allocation that recognizes positive and negative corporate taxable income. The Tax Agreement provides for an equitable method of apportioning the carryover of uncompensated tax benefits, which primarily relate to deferred synthetic fuels tax credits. Since 2002, Progress Energy tax benefits not related to acquisition interest expense have been allocated to profitable subsidiaries in accordance with a PUHCA 1935 order. Except for the allocation of these Progress Energy tax benefits, income taxes are provided as if PEC and PEF filed separate returns. Due to the repeal of PUHCA 1935, effective February 8, 2006, we stopped allocating these tax benefits.

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

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

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

We review our investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline in value exists, the investments are written down to fair value with a new cost basis established.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, we are required to write-down capitalized costs to this level. We performed this ceiling test calculation every quarter prior to the sale of our natural gas drilling and production business (See Note 3B). No write-downs were required in 2006, 2005 or 2004.

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS No. 158). SFAS No. 158 requires an entity to recognize in its statement of financial condition the funded status of its 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 employer's fiscal year (with limited exceptions). SFAS No. 158 also requires an entity to recognize changes in the funded status of a pension or other postretirement benefit plan within accumulated other comprehensive income (AOCI), net of tax, to the extent such changes are not recognized in earnings as components of net periodic cost. SFAS No. 158 does not permit retrospective application of its provisions. The recognition and disclosure provisions of SFAS No. 158 were implemented by us as of December 31, 2006. The implementation of SFAS No. 158 had no impact on reported net income.

The following is a summary of the incremental effect of applying the provisions of SFAS No. 158 on individual line items of the Balance Sheets of the Progress Registrants at December 31, 2006.

Progress Energy

(in millions)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory assets	$892	$339	$1,231
Intangibles, net	39	(39)	–
Total assets	25,401	300	25,701
Liabilities of discontinued operations	185	4	189
Income taxes accrued	287	(3)	284
Other current liabilities	746	9	755
Noncurrent income tax liabilities	255	51	306
Accrued pension and other benefits	791	166	957
Accumulated other comprehensive loss	(122)	73	(49)
Total capitalization and liabilities	25,401	300	25,701

PEC

(in millions)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory assets	$534	$243	$777
Other assets and deferred debits	180	(25)	155
Total assets	11,802	218	12,020
Income taxes accrued	69	(1)	68
Other current liabilities	152	2	154
Noncurrent income tax liabilities	855	54	909
Accrued pension and other benefits	501	80	581
Accumulated other comprehensive loss	(84)	83	(1)
Total capitalization and liabilities	11,802	$218	12,020

PEF

(in millions)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory assets	$330	$124	$454
Prepaid pension cost	221	(47)	174
Total assets	8,516	77	8,593
Other current liabilities	87	2	89
Noncurrent income tax liabilities	465	1	466
Accrued pension and other benefits	258	74	332
Total capitalization and liabilities	8,516	$77	8,593

Amounts for PEC and PEF that would otherwise be recorded in AOCI pursuant to SFAS No. 158 are recorded as regulatory assets consistent with the recovery of the related costs through the ratemaking process.

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

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). Enterprises must adopt FIN 48 through a cumulative effect adjustment to retained earnings at the beginning of their first fiscal year that begins after December 15, 2006, which for us was January 1, 2007. FIN 48 applies to all tax positions within the scope of SFAS No. 109, "Accounting for Income Taxes," and includes tax positions taken and tax positions expected to be taken. A two-step process is required for the application of FIN 48: recognition of the tax benefit based on a "more likely than not" threshold and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority. FIN 48 also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. We are still in the process of assessing the impact of FIN 48 on our various income tax positions. The cumulative effect adjustment to retained earnings upon adoption of FIN 48 could have a material impact on our financial statements.

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 redefines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." SFAS No. 157 establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. We will implement SFAS No. 157 as of January 1, 2008, applying the provisions retrospectively for derivative accounting and prospectively for all other valuations. We are currently evaluating the impact adoption may have on our financial condition, results of operations and cash flows.

Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). In practice, some companies currently use the "rollover" method, which focuses on the impact of a misstatement on the income statement. Other companies use the "iron curtain" method, which focuses on the impact of a misstatement on the balance sheet. SAB 108 requires companies to use a "dual approach" in quantifying financial statement misstatements. If an error is determined to be material under either approach, the financial statements must be adjusted. SAB 108 also provides transition guidance for correcting errors existing in prior years.

The SEC permits two methods for the initial application of SAB 108. A company can elect to restate prior financial statements as if the "dual approach" had always been used, or it can record a cumulative effect, with any correcting adjustments recorded to the carrying values of assets and liabilities as of the beginning of the implementation year with the offsetting adjustment recorded to the opening balance of retained earnings. Companies using the "cumulative effect" transition method must disclose the nature and amount of each individual error, including when and how each error being corrected arose. They must also disclose the fact that the errors had previously been considered immaterial. Companies do not have to restate prior period financial statements at initial application so long as management properly applied its previous approach.

SAB 108 is effective for us at December 31, 2006. The implementation of SAB 108 did not have a material effect on our financial position or results of operations, and we did not record an adjustment to beginning retained earnings as permitted by SAB 108.

3. DIVESTITURES

A. CCO – Georgia Operations

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of Progress Ventures, Inc.'s (PVI) Competitive Commercial Operations (CCO) physical and commercial assets, which include approximately 1,900 MW of power generation facilities in Georgia, as well as forward gas and power contracts, gas transportation, storage and structured power and other contracts, including the full requirements contracts with 16 Georgia Electric Membership Cooperatives (the Georgia Contracts). The operations of CCO were previously included in the former Progress Ventures segment. We expect to complete the disposition plan in 2007. As a result of the disposition plan, we recorded an after-tax estimated loss of $226 million in December 2006. In 2007, we anticipate recording additional material charges in discontinued operations related to the disposition plan. These additional charges relate primarily to costs to be incurred to exit the Georgia Contracts under SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." These costs could exceed $200 million after-tax.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $36 million, $39 million and $40 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $14 million, $14 million and $15 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$754**	$627	$168
Loss before income taxes	**$(92)**	$(93)	$(39)
Income tax benefit	**35**	39	16
Net loss from discontinued operations	**(57)**	(54)	(23)
Estimated loss on disposal of discontinued operations, including income tax benefit of $123	**(226)**	–	–
Loss from discontinued operations	**$(283)**	$(54)	$(23)

B. Natural Gas Drilling and Production

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

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006.

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production, which were previously included in the former Progress Ventures segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting, the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. Upon the sale of Gas, the gain was reclassed from continuing operations to earnings from discontinued operations.

The accompanying consolidated financial statements have been restated for all periods presented to reflect all the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $13 million, $13 million and $14 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $16 million, $26 million and $27 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$192**	$159	$162
Earnings before income taxes	**$135**	$73	$127
Income tax expense	**(53)**	(25)	(51)
Net earnings from discontinued operations	**82**	48	76
Gain on disposal of discontinued operations, including income tax expense of $188	**300**	–	–
Earnings from discontinued operations	**$382**	$48	$76

C. CCO – DeSoto and Rowan Generation Facilities

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

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

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $6 million, $13 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $3 million, $8 million and $8 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$64**	$67	$72
Earnings before income taxes	**$15**	$5	$13
Income tax expense	**(5)**	(2)	(5)
Net earnings from discontinued operations	**10**	3	8
Loss on disposal of discontinued operations, including income tax benefit of $37	**(67)**	–	–
(Loss) earnings from discontinued operations	**$(57)**	$3	$8

D. Progress Telecom, LLC

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

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

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of PT LLC as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $1 million for each of the years ended December 31, 2005 and 2004. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $1 million, $8 million and $6 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$18**	$76	$69
Earnings (loss) before income taxes and minority interest	**$7**	$11	$(9)
Income tax (expense) benefit	**(4)**	(3)	2
Minority interest	**(5)**	(4)	–
Net (loss) earnings from discontinued operations	**(2)**	4	(7)
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35	**28**	–	–
Earnings (loss) from discontinued operations	**$26**	$4	$(7)

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

E. Dixie Fuels and Other Fuels Business

On March 1, 2006, we sold our 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units operating under long-term contracts with PEF. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels. The other fuels business is Progress Materials, Inc. and is expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $1 million for each of the years ended December 31, 2006, 2005 and 2004. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $1 million, $2 million and $3 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$20**	$32	$25
Earnings before income taxes	**$11**	$8	$3
Income tax expense	**(4)**	(3)	(1)
Net earnings from discontinued operations	**7**	5	2
Gain on disposal of discontinued operations, including income tax expense of $1	**2**	–	–
Earnings from discontinued operations	**$9**	$5	$2

F. Coal Mining Businesses

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets. The remaining coal mining operations are expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $1 million, $3 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the years ended December 31, 2005 and 2004 was $10 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$84**	$184	$160
Loss before income taxes	**$(11)**	$(16)	$(17)
Income tax benefit	**7**	5	12
Net loss from discontinued operations	**(4)**	(11)	(5)
Loss on disposal of discontinued operations, including income tax benefit of $16	**(10)**	–	–
Loss from discontinued operations	**$(14)**	$(11)	$(5)

G. Progress Rail

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

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners, LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

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

(in millions)	**2006**	2005	2004
Revenues	**$–**	$358	$1,127
Earnings before income taxes	**$–**	$8	$50
Income tax expense	**–**	(3)	(21)
Net earnings from discontinued operations	**–**	5	29
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	**(6)**	(25)	–
(Loss) earnings from discontinued operations	**$(6)**	$(20)	$29

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

H. Net Assets of Discontinued Operations

Included in net assets of discontinued operations are the assets and liabilities of CCO, the remaining coal mining operations and other fuels business at December 31, 2006, and the assets and liabilities of CCO, Gas, DeSoto and Rowan, PT LLC, Dixie Fuels, the five coal mining businesses and other fuels business at December 31, 2005. The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2006**	December 31, 2005
Accounts receivable	**$45**	$115
Inventory	**24**	50
Other current assets	**28**	47
Total property, plant and equipment, net	**573**	1,899
Total other assets	**217**	455
Assets of discontinued operations	**$887**	$2,566
Accounts payable	**$43**	$87
Accrued expenses	**122**	233
Long-term liabilities	**24**	222
Liabilities of discontinued operations	**$189**	$542

I. Winter Park Distribution Assets

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

J. Synthetic Fuels Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million, $30 million and $8 million in the years ended December 31, 2006, 2005 and 2004, respectively. In the event that the synthetic fuels tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuels tax credits, the amount of proceeds realized from the sale could be significantly impacted.

K. North Carolina Natural Gas Corporation

On September 30, 2003, we sold North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company to Piedmont Natural Gas Company, Inc. During 2004, we recorded an additional tax gain of approximately $6 million due to final tax adjustments related to the divestiture of NCNG.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent (Bcf) from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005 or 2004. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3B).

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	**2006**	2005	**2006**	2005	**2006**	2005
Production plant	7-43	**$12,685**	$12,489	**$8,422**	$8,260	**$4,078**	$4,039
Transmission plant	17-75	**2,509**	2,353	**1,300**	1,264	**1,209**	1,089
Distribution plant	13-55	**7,351**	7,015	**3,992**	3,838	**3,359**	3,177
General plant and other	5-35	**1,198**	1,083	**642**	632	**556**	451
Utility plant in service		**$23,743**	$22,940	**$14,356**	$13,994	**$9,202**	$8,756

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

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 8.7%, 5.6% and 7.2% in 2006, 2005 and 2004, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2006 and 7.8% in 2005 and 2004.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7%, 2.5% and 2.2% in 2006, 2005 and 2004, respectively. The depreciation provisions related to utility plant were $628 million, $556 million and $463 million in 2006, 2005 and 2004, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 21B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2006, 2005 and 2004 was $140 million, $136 million and $137 million, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.8%, 2.7% and 2.1% in 2006, 2005 and 2004, respectively. The depreciation provisions related to utility plant were $389 million, $365 million and $275 million in 2006, 2005 and 2004, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Note 7A) and Clean Smokestacks Act amortization (See Note 21B).

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

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7% in 2006 and 2.3% in 2005 and 2004. The depreciation provisions related to utility plant were $239 million, $191 million and $188 million in 2006, 2005 and 2004, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 21).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2006, 2005 and 2004 was $109 million, $107 million and $105 million, respectively, for PEC and $31 million, $29 million and $32 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

Progress Energy

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

(in millions)	**2006**	2005
Equipment (3-25 years)	**$66**	$79
Land and mineral rights	**16**	17
Buildings and plants (5-40 years)	**54**	66
Rail equipment (3-20 years)	**–**	37
Computers, office equipment and software (3-10 years)	**2**	2
Construction work in progress	**1**	2
Accumulated depreciation	**(108)**	(125)
Diversified business property, net	**$31**	$78

Diversified business depreciation expense was $13 million for December 31, 2006, and $22 million for December 31, 2005 and 2004.

PEC

Net diversified business property was $7 million at both December 31, 2006 and 2005. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 10 to 40 years. Accumulated depreciation was $2 million at both December 31, 2006 and 2005. Diversified business depreciation expense was less than $1 million each in 2006, 2005 and 2004. Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). 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:

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

2005 (in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$518	$255	$1
PEC	Harris	83.83%	3,146	1,459	17
PEC	Brunswick	81.67%	1,623	921	23
PEC	Roxboro Unit 4	87.06%	355	153	10
PEF	Crystal River Unit 3	91.78%	808	493	48
PEF	Intercession City Unit P11	66.67%	24	4	–

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

D. Asset Retirement Obligations

At December 31, 2006 and 2005, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation for PEC, totaled $30 million and $31 million, respectively. No costs related to nuclear decommissioning of irradiated plant were recorded at December 31, 2006 and 2005 at PEF. At December 31, 2006 and 2005, additional PEF-related asset retirement costs, net of accumulated depreciation, of $126 million and $137 million, respectively, were recorded at Progress Energy. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $735 million and $640 million at December 31, 2006 and 2005, respectively, for PEC and $552 million and $493 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2006, 2005 and 2004. Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset retirement obligations, which are included in depreciation and amortization expense, were $96 million, $90 million and $83 million in 2006, 2005 and 2004, respectively, for PEC and $27 million, $78 million and $77 million in 2006, 2005 and 2004, respectively, for PEF.

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

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

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Removal costs	**$1,341**	$1,316	**$727**	$661	**$614**	$655
Nonirradiated decommissioning costs	**137**	132	**76**	71	**61**	61
Dismantlement costs	**124**	123	**–**	–	**124**	123
Non-ARO cost of removal	**$1,602**	$1,571	**$803**	$732	**$799**	$839

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2, and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. Extended NRC operating licenses held by PEC currently expire in July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. An application to extend the licenses 20 years for the Brunswick units was approved in June 2006. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. PEF's reserve for fossil plant dismantlement was approximately $145 million at December 31, 2006 and 2005, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

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

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

Our nonregulated AROs relate to the synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $3 million at December 31, 2006 and 2005.

The following table presents the changes to the AROs during the years ended December 31, 2006 and 2005. Additions relate primarily to asbestos abatement at the Utilities. Revisions to prior estimates of the PEC regulated ARO are related to remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2005	$1,261	$2	$924	$337
Additions	50	–	23	27
Accretion expense	65	1	51	14
Revisions to prior estimates	(137)	–	(49)	(88)
Asset retirement obligations at December 31, 2005	1,239	3	949	290
Accretion expense	**72**	–	**57**	**15**
Revisions to prior estimates	**(8)**	–	**(2)**	**(6)**
Asset retirement obligations at December 31, 2006	**$1,303**	**$3**	**$1,004**	**$299**

E. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $33 million with respect to the primary coverage, $36 million with respect to the decontamination, decommissioning and excess property coverage, and $24 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.760 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $100 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $15 million per reactor owned.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to terrorist acts.

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

6. CURRENT ASSETS

A. Receivables

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

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Trade accounts receivable	**$628**	$661	**$285**	$336	**$288**	$263
Unbilled accounts receivable	**227**	227	**157**	158	**55**	60
Notes receivable	**57**	83	**–**	–	**–**	–
Other receivables	**46**	45	**36**	28	**5**	14
Allowance for doubtful accounts receivable	**(28)**	(19)	**(5)**	(4)	**(8)**	(6)
Total receivables	**$930**	$997	**$473**	$518	**$340**	$331

B. Inventory

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Fuel for production	**$470**	$321	**$230**	$185	**$240**	$136
Inventory for sale	**34**	61	**–**	–	**–**	–
Materials and supplies	**443**	406	**247**	240	**194**	166
Emission allowances	**22**	35	**20**	26	**2**	9
Total current inventory	**$969**	$823	**$497**	$451	**$436**	$311

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy and PEC of $44 million at December 31, 2006 and 2005.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $14 million, $13 million and $1 million, respectively, at December 31, 2005. Progress Energy, PEC and PEF did not have any long-term emission allowance amounts at December 31, 2006.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

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

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

Progress Energy

(in millions)	2006	2005
Deferred fuel cost – current (Note 7B)	**$196**	$602
Deferred fuel cost – long-term (Note 7B)	**114**	31
Deferred impact of ARO – PEC (Note 1D)	**282**	281
Income taxes recoverable through future rates (Note 14)	**114**	81
Loss on reacquired debt (Note 1D)	**46**	50
Storm deferral (Notes 7B and 7C)	**102**	227
Postretirement benefits (Note 16)	**373**	88
Derivative mark-to-market adjustment (Note 17)	**78**	6
Environmental (Notes 7B, 7C and 21A)	**72**	26
Other	**50**	64
Total long-term regulatory assets	**1,231**	854
Deferred fuel cost – current (Note 7C)	**(63)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(13)**	(10)
Total current regulatory liabilities	**(76)**	(10)
Non-ARO cost of removal (Note 5D)	**(1,602)**	(1,571)
Deferred impact of ARO – PEF (Note 1D)	**(221)**	(225)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(330)**	(251)
Clean Smokestacks Act compliance (Note 21B)	**(333)**	(317)
Derivative mark-to-market adjustment (Note 17A)	**–**	(122)
Other	**(57)**	(41)
Total long-term regulatory liabilities	**(2,543)**	(2,527)
Net regulatory liabilities	**$(1,192)**	$(1,081)

PEC

(in millions)	**2006**	2005
Deferred fuel cost – current (Note 7B)	**$196**	$261
Deferred fuel cost – long-term (Note 7B)	**114**	31
Deferred impact of ARO (Note 1D)	**282**	281
Income taxes recoverable through future rates (Note 14)	**50**	22
Loss on reacquired debt (Note 1D)	**19**	21
Storm deferral (Note 7B)	**12**	19
Postretirement benefits (Note 16)	**243**	–
Environmental (Note 7B)	**15**	–
Other	**42**	47
Total long-term regulatory assets	**777**	421
Non-ARO cost of removal (Note 5D)	**(803)**	(732)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(171)**	(135)
Clean Smokestacks Act compliance (Note 21B)	**(333)**	(317)
Other	**(13)**	(12)
Total long-term regulatory liabilities	**(1,320)**	(1,196)
Net regulatory liabilities	**$(347)**	$(514)

PEF

(in millions)	**2006**	2005
Deferred fuel cost – current (Note 7C)	$–	$341
Storm deferral (Note 7C)	**90**	208
Income taxes recoverable through future rates (Note 14)	**64**	59
Loss on reacquired debt (Note 1D)	**27**	29
Postretirement benefits (Note 16)	**130**	7
Derivative mark-to-market adjustment (Note 17A)	**78**	6
Environmental (Notes 7C and 21A)	**57**	26
Other	**8**	16
Total long-term regulatory assets	**454**	351
Deferred fuel cost – current (Note 7C)	**(63)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(13)**	(10)
Total current regulatory liabilities	**(76)**	(10)
Non-ARO cost of removal (Note 5D)	**(799)**	(839)
Deferred impact of ARO (Note 1D)	**(88)**	(80)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(159)**	(116)
Derivative mark-to-market adjustment (Note 17A)	–	(122)
Other	**(45)**	(32)
Total long-term regulatory liabilities	**(1,091)**	(1,189)
Net regulatory liabilities	**$(713)**	$(507)

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 these assets and refund these liabilities through customer rates under current regulatory practice.

B. PEC Retail Rate Matters

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. Subsequent to 2007, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation.

FUEL COST RECOVERY

On May 3, 2006, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers for under-recovered fuel costs and to meet future expected fuel costs. On June 16, 2006, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement provided for a $23 million, or 4.6 percent, increase in rates. The increase was $4 million less than PEC originally requested due to adjustment of future fuel cost estimates agreed upon during settlement. Effective July 1, 2006, residential electric bills increased by $3.01 per 1,000 kWhs for fuel cost recovery. At December 31, 2006, PEC's South Carolina deferred fuel balance was $29 million, of which $5 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

On June 2, 2006, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. On September 25, 2006, the NCUC approved a settlement agreement filed jointly by PEC, the NCUC Public Staff and the Carolinas Industrial Group for Fair Utility Rates II. The settlement agreement provided for a $177 million, or 6.7 percent increase in rates effective October 1, 2006. The settlement agreement further provides for rate increases of $50 million in 2007 and $30 million in 2008 and for PEC to collect its existing deferred fuel balance by September 30, 2009. PEC initially sought an increase of $292 million, or 11.0 percent, but agreed to a three-year phase-in of the increase in order to address concerns regarding the magnitude of the proposed increase. PEC will be allowed to calculate and collect interest at 6% on the difference between its fuel factor proposed in its original request to the NCUC and the settlement agreement's factor. Effective October 1, 2006, residential electric bills increased by $4.87 per 1,000 kWhs for fuel cost recovery. At December 31, 2006, PEC's North Carolina deferred fuel balance was $281 million, of which $109 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

The Carolina Utility Customers Association (CUCA) appealed the NCUC's order on November 21, 2006 on the grounds that the NCUC does not have the statutory authority to establish fuel rates for more than one year. We anticipate filing a motion to dismiss during the first quarter of 2007. We cannot predict the outcome of this matter.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. During each of 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. During each of 2006, 2005 and 2004, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in the fourth quarter of 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense.

As discussed in Note 21B, PEC reclassified $29 million of expense from other, net to depreciation and amortization expense on the Consolidated Statements of Income for Clean Smokestacks Act amortization recognized during 2006.

The NCUC and SCPSC have approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively. Accelerated cost recovery of these assets resulted in no additional expense in 2006, 2005 or 2004. Through December 31, 2006, PEC recorded total accelerated depreciation of $403 million.

C. PEF Retail Rate Matters

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010. Additionally, PEF will continue to recover and collect a return on Hines Unit 2 through the fuel clause through late 2007, when it will be transferred into base rates. This transfer will correspond with the in-service dates of Hines Unit 4, which will also be recovered through a base rate increase. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2006 threshold of $1.499 billion and thus no revenues were subject to revenue sharing. Both the 2006 base threshold of $1.499 billion and the 2006 cap of $1.549 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent return on equity (ROE) for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PASS-THROUGH CLAUSE COST RECOVERY

On September 1 and September 15, 2006, PEF filed requests with the FPSC seeking increases to cover rising fuel, environmental compliance and energy conservation costs. PEF asked the FPSC to approve a $171 million, or 3.7 percent, increase in rates. Subsequently, on October 25 and October 31, 2006, PEF supplemented its September filings to reflect lower projected fuel costs for PEF. PEF's revised forecasts resulted in a $40 million, or 0.7 percent, increase in rates over 2006. On November 8, 2006, the FPSC approved PEF's supplemental filing. The new charges were effective January 1, 2007, and increased residential bills $0.78 for the first 1,000 kWhs. At December 31, 2006, PEF was over-recovered in fuel and capacity costs by $63 million and under-recovered in environmental compliance by $14 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claims that although CR4 and CR5 were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On August 30, 2006, PEF filed a motion with the FPSC to dismiss the petition on the grounds that the OPC petition would require the FPSC to engage in retroactive ratemaking for rates previously approved under the fuel recovery clause. On September 13, 2006, the OPC filed a memorandum in opposition to PEF's motion to dismiss the petition. PEF's motion to dismiss was denied by the FPSC on December 19, 2006. A hearing on the matter has been scheduled by the FPSC for April 2, 2007. PEF believes that its coal procurement practices were prudent and that it has sound legal and factual arguments to successfully defend its position. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for determination of need to uprate CR3, bid rule exemption and recovery of the costs through PEF's fuel recovery clause. The uprate will increase CR3's gross output by approximately 180 MW. The uprate will take place in two stages: approximately 40 MW will be added through equipment modifications during the 2009 refueling outage and approximately 140 MW will be added by modifying the design of the plant during the 2011 refueling outage to use more highly enriched fuel. The design modifications will require a license amendment approved by the NRC. The project is estimated to cost approximately $382 million, which includes potential transmission system improvements and modifications to comply with environmental regulations. The costs may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery of uprate costs through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. The FPSC has scheduled a hearing to be held May 23, 2007, to determine whether the uprate costs should be recovered through the fuel adjustment clause. If PEF does not receive approval to recover the uprate costs through the fuel adjustment clause, these costs will be recoverable through base rates, similar to other utility plant additions. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. We cannot predict the outcome of this matter.

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWhs beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as O&M expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006. In 2006 and 2005, PEF recorded amortization of $122 million and $50 million, respectively, associated with the recovery of these storm costs.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWhs, for an additional 12-month period to replenish its storm reserve. The requested extension, which would begin August 2007, would replenish the existing storm reserve by an estimated additional $130 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified.

FRANCHISE MATTERS

On June 1, 2005, Winter Park acquired PEF's electric distribution system that serves Winter Park for approximately $42 million. On June 1, 2005, PEF transferred the distribution system to Winter Park and recognized a pre-tax gain of approximately $25 million on the transaction, which is included as an offset to other utility expense on the Statements of Income. This amount was decreased $1 million in the third quarter of 2005 upon accumulation of the final capital expenditures incurred since arbitration. PEF also recorded a regulatory liability of $8 million for stranded cost revenues, which will be amortized to revenues over six years in accordance with the provisions of the transfer agreement with Winter Park. In June 2004, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option.

OTHER MATTERS

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. The unit is planned for commercial operation in December 2007. Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating). The estimated total in-service cost of Hines Unit 4 approved as part of the Determination of Need was $286 million. If the actual cost is less than the original estimate, ratepayers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent, among other things, extraordinary circumstances as found by the FPSC in subsequent proceedings. The current estimate of in-service cost exceeds the initial project estimate by approximately 12 percent to 15 percent due to what we believe to be extraordinary circumstances. Therefore, we believe that disallowance of these costs by the FPSC in subsequent proceedings is not probable. We cannot predict the outcome of this matter.

D. Regional Transmission Organizations

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (RTOs) must meet, including independent transmission service. In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO. PEC participated in the mediation; no consensus was reached on creating a Southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC's investment in GridSouth totaled $33 million at December 31, 2006 and 2005. PEC expects to recover its investment.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved. PEF fully recovered its startup costs in GridFlorida from retail ratepayers through base rates.

E. Nuclear License Renewals

On June 26, 2006, Brunswick received 20-year extensions from the NRC on the operating licenses for its two nuclear reactors. The operating licenses have been extended to 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved.

F. FERC Market Power Mitigation

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

8. GOODWILL AND OTHER INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2005 and 2006; each test indicated no impairment.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. At December 31, 2006 and 2005, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. There were no changes to the assignment of the carrying amounts to PEC and PEF in 2006 or 2005.

Included in the assets of discontinued operations at December 31, 2005, is the goodwill related to CCO. For CCO, the goodwill impairment tests were performed at the reporting unit level of our Effingham, Monroe, Walton and Washington nonregulated generating plants (Georgia Region), which is one level below CCO. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Region operations, we performed an interim goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which was previously reported within impairment of assets on the Consolidated Statements of Income. This impairment was reclassed to discontinued operations on the Consolidated Statements of Income during the fourth quarter of 2006 (See Note 3A).

The gross carrying amount and accumulated amortization of the intangible assets at December 31 were as follows:

	2006		2005	
(in millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Synthetic fuels intangibles	**$107**	**$(107)**	$134	$(98)
Other	**6**	**(6)**	29	(6)
Total	**$113**	**$(113)**	$163	$(104)

All of our intangibles, except minimum pension liability adjustments, are subject to amortization. Synthetic fuels intangibles represent intangibles for synthetic fuels technology. Other intangibles are primarily acquired customer contracts, permits that are amortized over their respective lives and minimum pension liability adjustments.

PEC had intangible assets related to minimum pension liability adjustments of $17 million at December 31, 2005. PEF had intangible assets related to minimum pension liability adjustments of $2 million at December 31, 2005. Due to the adoption of SFAS No. 158 in 2006, minimum pension liability adjustments and related intangible assets are no longer recorded (See Note 2).

Amortization expense recorded on intangible assets was $9 million for the year ended December 31, 2006, and $19 million for both years ended December 31, 2005 and 2004. No amortization expense on intangible assets was recorded at PEC and PEF for each of the years ended December 31, 2006, 2005 and 2004. No annual amortization expense for intangible assets is expected for 2007 through 2011.

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which is reported within impairment of assets on the Consolidated Statements of Income. This charge represents the entirety of the synthetic fuels intangible assets; these assets had been reported within the Coal and Synthetic Fuels segment. Following a significant decrease in oil prices, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006.

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2006 and 2005, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million and $1 million, respectively. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million in both 2006 and 2005. No impairments were recorded in 2004.

A. Long-Lived Assets

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which is reported within impairment of assets on the Consolidated Statements of Income. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within the Coal and Synthetic Fuels segment. As discussed in Note 8, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006.

B. Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D).

Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. As a result of various factors, including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million on a pre-tax basis in both 2006 and 2005. No impairments were recorded in 2004.

10. EQUITY

A. Common Stock

Progress Energy

At December 31, 2006 and 2005, we had 500 million shares of common stock authorized under our charter, of which 256 million shares and 252 million shares, respectively, were outstanding. During 2006, 2005 and 2004, respectively, we issued approximately 4.2 million, 4.8 million and 1.7 million shares of common stock, resulting in approximately $185 million, $208 million and $73 million in proceeds. Included in these amounts for 2006, 2005 and 2004, respectively, were approximately 1.6 million, 4.6 million and 1.4 million shares for proceeds of approximately $70 million, $199 million and $62 million, to meet the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2006 and 2005, we had approximately 54 million shares and 58 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2006, there were no significant restrictions on the use of retained earnings (See Note 12).

PEC

At December 31, 2006 and 2005, 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, 2006, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEC.

PEF

At December 31, 2006 and 2005, 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, 2006, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEF.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2006 and 2005, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 2.3 million and 2.9 million ESOP suspense shares at December 31, 2006 and 2005, respectively, with a fair value of $112 million and $126 million, respectively. ESOP shares allocated to plan participants totaled 10.9 million and 11.4 million at December 31, 2006 and 2005, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $14 million, $18 million and $21 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $23 million, $30 million and $32 million for the years ended December 31, 2006, 2005 and 2004, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $8 million, $11 million and $12 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $13 million, $17 million and $18 million for the years ended December 31, 2006, 2005 and 2004, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $2 million, $4 million and $5 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $4 million, $6 million and $7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005 or 2006. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

Progress Energy

A summary of the status of our stock options at December 31, 2006, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	7.0	$43.58
Granted	–	–
Forfeited	(0.1)	44.75
Canceled	(0.2)	43.74
Exercised	(2.7)	43.37
Options outstanding, December 31	4.0	43.70
Options exercisable, December 31	4.0	43.70

The options outstanding and exercisable at December 31, 2006, had a weighted-average remaining contractual life of 5.8 years and an aggregate intrinsic value of $22 million. Total intrinsic value of options exercised during the year ended December 31, 2006, was $10 million. Total intrinsic value of options exercised during the year ended December 31, 2005, was less than $1 million. The total intrinsic value of options exercised during the year ended December 31, 2004, was $1 million.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the grant date using a Black-Scholes option pricing model with the following weighted-average assumptions:

	2004
Risk-free interest rate	4.22%
Dividend yield	5.19%
Volatility factor	20.30%
Weighted-average expected life of the options (in years)	10

Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year. Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income and earnings per share if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions except per share data)	2005	2004
Net income, as reported	$697	$759
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2	10
Pro forma net income	$695	$749
Earnings per share		
Basic – as reported	$2.82	$3.13
Basic – pro forma	2.81	3.09
Diluted – as reported	2.82	3.12
Diluted – pro forma	2.81	3.08

As of December 31, 2006, all options were fully vested and no compensation expense related to stock options is expected in future periods.

Cash received from the exercise of stock options totaled $115 million, $8 million and $18 million, respectively, during the years ended December 31, 2006, 2005 and 2004. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2006, was $4 million. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2005 and 2004 was not significant.

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options are fully vested and no compensation expense related to stock options is expected in future periods.

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions)	2005	2004
Net income, as reported	$493	$461
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2	7
Pro forma net income	$491	$454

PEF

Stock option expense totaling less than $1 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. As of December 31, 2006, all options are fully vested and no compensation expense related to stock options is expected in future periods.

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions)	2005	2004
Net income, as reported	$260	$335
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	1	2
Pro forma net income	$259	$333

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards (RSA) program, both of which were established pursuant to our 1997 Equity Incentive Plan and were continued under our 2002 Equity Incentive Plan, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Beginning in 2005, we are granting stock-settled PSSP awards. Under the terms of the cash-settled PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on our results as compared to a peer group of utilities. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. Compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with certain subsequent adjustments related to our results as compared to the peer group of utilities. PSSP cash-settled liabilities totaling $4 million, $5 million and $7 million were paid in the years ended December 31, 2006, 2005 and 2004, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2006, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares [a]	Weighted-Average Grant Date Fair Value
Beginning balance	540,588	$44.24
Granted	556,431	44.27
Paid	(54)	44.27
Vested	–	–
Forfeited	(52,382)	44.25
Ending balance	1,044,583	$44.26

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

For the year ended December 31, 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.24.

The RSA program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2006, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	588,308	$43.27
Granted	168,800	44.51
Vested	(102,836)	41.87
Forfeited	(50,034)	43.68
Ending balance	604,238	$43.82

For the years ended December 31, 2005 and 2004, the weighted-average grant date fair value of restricted stock granted was $42.56 and $46.95, respectively.

The total fair value of restricted stock vested during the years ended December 31, 2006, 2005 and 2004 was $4 million, $7 million and $16 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million, $8 million and $7 million during the years ended December 31, 2006, 2005 and 2004, respectively.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $25 million for the year ended December 31, 2006, with a recognized tax benefit of $10 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $10 million, with a recognized tax benefit of $4 million, for each of the years ended December 31, 2005 and 2004. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2006, there was $33 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 2.1 years.

PEC

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $14 million for the year ended December 31, 2006, with a recognized tax benefit of $6 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $7 million, with a recognized tax benefit of $3 million, for each of the years ended December 31, 2005 and 2004. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

Our Statements of Income included total recognized expense for other stock-based compensation plans of $7 million for the year ended December 31, 2006, with a recognized tax benefit of $3 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $3 million for the year ended December 31, 2005, with a recognized tax benefit of $1 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $2 million for the year ended December 31, 2004, with a recognized tax benefit of $1 million. No compensation cost related to other stock-based compensation plans was capitalized.

C. Earnings Per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effect of the nonvested portion of restricted stock awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	**2006**	2005	2004
Weighted-average common shares – basic	**250.4**	246.6	242.2
Net effect of dilutive stock-based compensation plans	**0.4**	0.4	0.9
Weighted-average shares – fully diluted	**250.8**	247.0	243.1

There were no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 2.4 million, 3.0 million and 3.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. There were 1.8 million, 2.9 million and 3.0 million stock options outstanding at December 31, 2006, 2005 and 2004, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss, net of tax, at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
(Loss) gain on cash flow hedges	**$(14)**	$55	**$(5)**	$(3)	**$(1)**	$–
Minimum pension liability adjustments	**–**	(160)	**–**	(119)	**–**	–
SFAS No. 158 benefits adjustment	**(39)**	–	**–**	–	**–**	–
Other	**4**	1	**4**	2	**–**	–
Total accumulated other comprehensive loss	**$(49)**	$(104)	**$(1)**	$(120)	**$(1)**	$–

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

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2006 and 2005, preferred stock outstanding consisted of the following:

	Shares		Redemption	
(dollars in millions, except share and per share data)	Authorized	Outstanding	Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	$104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2006):

(in millions)		**2006**	2005
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	**$2,600**	$4,300
Unamortized fair value hedge gain, net		**(1)**	(3)
Unamortized premium and discount, net		**(18)**	(19)
Current portion of long-term debt		**–**	(404)
Long-term debt, net		**2,581**	3,874
PEC			
First mortgage bonds, maturing 2007-2033	5.76%	**2,200**	2,200
Pollution control obligations, maturing 2017-2024	3.74%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	22
Unamortized premium and discount, net		**(21)**	(24)
Current portion of long-term debt		**(200)**	–
Long-term debt, net		**3,470**	3,667
PEF			
First mortgage bonds, maturing 2008-2033	5.39%	**1,630**	1,630
Pollution control obligations, maturing 2018-2027	3.66%	**241**	241
Senior unsecured notes, maturing 2008	5.77%	**450**	450
Medium-term notes, maturing 2007-2028	6.77%	**241**	289
Unamortized premium and discount, net		**(5)**	(8)
Current portion of long-term debt		**(89)**	(48)
Long-term debt, net		**2,468**	2,554
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(38)**	(39)
Long-term debt, net		**271**	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2007-2008	6.59%	**80**	140
Miscellaneous notes		**–**	2
Current portion of long-term debt		**(35)**	(61)
Long-term debt, net		**45**	81
Progress Energy consolidated long-term debt, net		**$8,835**	$10,446

At December 31, 2005, we classified $397 million, related to the retirement of $800 million in Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation was not expected to require the use of working capital in 2006 as we had the intent and ability to refinance this debt on a long-term basis.

On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of $397 million. These senior notes are unsecured. Interest on the Floating Rate Senior Notes is based on three-month London Inter Bank Offering Rate

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

On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand and no additional debt was incurred in connection with the redemption. See Note 20 for a discussion of losses on debt redemptions.

At December 31, 2006 and 2005, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2006 and 2005, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2006:

(in millions)	Description	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$1,130	$ –	$(60)	$1,070
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$ –	$(60)	$1,970

[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, 2006, Progress Energy, Inc. had a total amount of $60 million of letters of credit issued, which were supported by the RCA.

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

On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006. The new RCA will continue to be used to provide liquidity support for Progress Energy's issuances of commercial paper and other short-term obligations. The new RCA no longer includes a material adverse change representation for borrowings or a financial covenant for interest coverage. Fees and interest rates under the new RCA will continue to be determined based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's Investors Service, Inc. (Moody's) and BBB- by S&P.

On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P.

On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB- by S&P.

We had no commercial paper outstanding or other short-term debt at December 31, 2006. The following table summarizes our outstanding commercial paper and other short-term debt and related weighted-average interest rates at December 31, 2005:

(in millions)		
PEC	4.65%	$73
PEF	4.75%	102
Total	4.71%	$175

The following table presents the aggregate maturities of long-term debt at December 31, 2006:

(in millions)	Progress Energy Consolidated	PEC	PEF
2007	$324	$200	$89
2008	877	300	532
2009	400	400	–
2010	406	6	300
2011	1,000	–	300
Thereafter	6,235	2,785	1,341
Total	$9,242	$3,691	$2,562

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2006, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio [(a)]
Progress Energy, Inc.	68%	55.4%
PEC	65%	52.3%
PEF	65%	49.4%

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

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

Additionally, certain of Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $2.6 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'s Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2006, Progress Energy, Inc. had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by Progress Energy, Inc.'s subsidiaries as outlined below.

PEC

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2006, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2006, PEC's common stock equity was approximately 49.0 percent of total capitalization. At December 31, 2006, 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, 2006, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2006, PEF's common stock equity was approximately 51.8 percent of total capitalization. At December 31, 2006, none of PEF's cash dividends or distributions on common stock was restricted.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2006, PEC and PEF had a total of $2.869 billion and $1.871 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 18 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. Hedging Activities

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 17 for a discussion of risk management activities and derivative transactions.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2006 and 2005, 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)	**2006**	2005	**2006**	2005	**2006**	2005
Nuclear decommissioning trust (See Note 5D)	**$1,287**	$1,133	**$735**	$640	**$552**	$493
Investments in equity securities [(a)]	**6**	7	**4**	6	**1**	1
Equity method investments [(b)]	**23**	27	**13**	15	**–**	–
Cost investments [(c)]	**8**	13	**2**	1	**–**	–
Benefit investment trusts [(d)]	**80**	77	**2**	1	**–**	–
Company-owned life insurance [(d)]	**161**	153	**99**	97	**39**	39
Marketable debt securities [(e)]	**71**	191	**50**	191	**–**	–
Total	**$1,636**	$1,601	**$905**	$951	**$592**	$533

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(b) Investments in unconsolidated companies are included in the Consolidated Balance Sheets in miscellaneous other property and investments using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20).

(c) Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(d) Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.

(e) We actively invest available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As we intend to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

Progress Energy

DEBT

The carrying amount of our long-term debt, including current maturities, was $9.159 billion and $10.959 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.543 billion and $11.491 billion at December 31, 2006 and 2005, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2006			
(in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$428**	**$324**	**$752**
Debt securities	**606**	**13**	**619**
Cash equivalents	**19**	**–**	**19**
Total	**$1,053**	**$337**	**$1,390**
2005			
(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$406	$257	$663
Debt securities	673	7	680
Cash equivalents	18	–	18
Total	$1,097	$264	$1,361

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$28
Due after one through five years	116
Due after five through 10 years	196
Due after 10 years	279
Total	$619

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2006**	2005	2004
Proceeds	**$2,547**	$3,755	$3,200
Realized gains	**33**	26	55
Realized losses	**24**	31	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2006 and 2005 for investments in these trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2006 and 2005 our other securities had no investments in a continuous loss position for greater than 12 months.

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $3.670 billion and $3.667 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.732 billion and $3.789 billion at December 31, 2006 and 2005, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the PEC Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust fund, PEC holds other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the PEC Consolidated Balance Sheets at amounts that approximate fair value. PEC's available-for-sale securities at December 31, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2006 (in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$232**	**$170**	**$402**
Debt securities	**364**	**7**	**371**
Cash equivalents	**9**	**–**	**9**
Total	**$605**	**$177**	**$782**
2005 (in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$218	$141	$359
Debt securities	461	4	465
Cash equivalents	10	–	10
Total	$689	$145	$834

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$18
Due after one through five years	80
Due after five through 10 years	76
Due after 10 years	197
Total	$371

Selected information about PEC's sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2006**	2005	2004
Proceeds	**$995**	$1,678	$2,584
Realized gains	**21**	13	24
Realized losses	**14**	16	25

Available-for-sale securities in PEC's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2006 and 2005 PEC's other securities had no investments in a continuous loss position for greater than 12 months.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $2.557 billion and $2.602 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2.567 and $2.635 billion at December 31, 2006 and 2005, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. PEF's available-for-sale securities at December 31, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2006			
(in millions)	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$196**	**$154**	**$350**
Debt securities	**184**	**6**	**190**
Cash equivalents	**9**	**–**	**9**
Total	**$389**	**$160**	**$549**
2005			
(in millions)	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$188	$116	$304
Debt securities	180	3	183
Cash equivalents	5	–	5
Total	$373	$119	$492

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was (in millions):

Due in one year or less	$3
Due after one through five years	26
Due after five through 10 years	100
Due after 10 years	61
Total	$190

Selected information about PEF's sales of available-for-sale securities for the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2006**	2005	2004
Proceeds	**$509**	$330	$529
Realized gains	**12**	13	30
Realized losses	**9**	13	5

Available-for-sale securities in PEF's nuclear decommissioning trust funds are impaired if they are in a loss position as described above. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2006 and 2005 PEF's other securities had no investments in a loss position.

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders.

Progress Energy

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2006**	2005
Deferred income tax assets		
Asset retirement obligation liability	**$141**	$155
Compensation accruals	**99**	99
Deferred revenue	**28**	55
Derivative instruments	**42**	–
Environmental remediation liability	**36**	27
Income taxes refundable through future rates	**216**	234
Investments	**5**	–
SFAS No. 158, postretirement and pension benefits	**351**	274
Unbilled revenue	**36**	30
Other	**125**	108
Federal income tax credit carry forward	**851**	957
State net operating loss carry forward (net of federal expense)	**54**	44
Valuation allowance	**(71)**	(39)
Total deferred income tax assets	**1,913**	1,944
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,349)**	(1,396)
Deferred fuel recovery	**(60)**	(89)
Deferred storm costs	**(51)**	(94)
Derivative instruments	**–**	(32)
Income taxes recoverable through future rates	**(436)**	(202)
Investments	**–**	(35)
Other	**(70)**	(64)
Total deferred income tax liabilities	**(1,966)**	(1,912)
Total net deferred income tax (liabilities) assets	**$(53)**	$32

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

(in millions)	**2006**	2005
Current deferred income tax assets	**$159**	$37
Noncurrent deferred income tax assets, included in other assets and deferred debits	**19**	79
Current deferred income tax liabilities, included in other current liabilities	**(1)**	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(230)**	(83)
Total net deferred income tax (liabilities) assets	**$(53)**	$32

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

At December 31, 2006, the federal income tax credit carry forward includes $850 million of alternative minimum tax credits that do not expire and $1 million of general business credits that will expire during the period 2023 through 2025.

At December 31, 2006, we had gross state net operating loss carry forwards of $1.1 billion that will expire during the period 2009 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $32 million during 2006. We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

We establish accruals for certain tax contingencies when, despite our belief that our tax return positions are fully supported, we believe that certain positions may be challenged and that it is probable our positions may not be fully sustained. We are under continuous examination by the IRS and other tax authorities, and we account for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

Considering all tax contingency reserves, we do not expect the resolution of these matters to have a material impact on our financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

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

	2006	2005	2004
Effective income tax rate	**28.1%**	(5.9)%	9.3%
State income taxes, net of federal benefit	**(6.5)**	(3.7)	(7.7)
Minority interest	**0.2**	(2.3)	(1.2)
Federal tax credits	**11.3**	43.7	30.2
Investment tax credit amortization	**1.7**	2.0	1.9
Employee stock ownership plan dividends	**1.7**	1.9	2.1
Domestic manufacturing deduction	**0.5**	1.3	–
Other differences, net	**(2.0)**	(2.0)	0.4
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Our effective income tax rate is favorably impacted by federal tax credits resulting from synthetic fuels production.

Income tax expense (benefit) applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	**2006**	2005	2004
Current – federal	**$377**	$382	$249
– state	**69**	78	71
Deferred – federal	**(136)**	(163)	(33)
– state	**(26)**	(36)	10
Valuation allowance	**14**	–	–
State net operating loss carry forward	**(3)**	(3)	(1)
Synthetic fuels tax credit	**(79)**	(282)	(215)
Investment tax credit	**(12)**	(13)	(14)
Total income tax expense (benefit)	**$204**	$(37)	$67

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2006 or 2004.

- Taxes related to discontinued operations recorded net of tax for 2006, 2005 and 2004, which are presented separately in Notes 3A through 3G.

- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $3 million related to excess tax deductions resulting from vesting of restricted stock, interim period vesting of stock-settled PSSP awards and exercises of nonqualified stock options, which was recorded in common stock during 2006. Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce synthetic fuels as defined under the Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29/45K, if certain requirements are satisfied.

PEC

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2006**	2005
Deferred income tax assets:		
Asset retirement obligation liability	**$132**	$131
Compensation accruals	**47**	46
Deferred revenue	**28**	55
Income taxes refundable through future rates	**68**	54
SFAS No. 158, postretirement and pension benefits	**200**	155
Other	**37**	49
Federal income tax credit carry forward	**1**	20
Total deferred income tax assets	**513**	510
Deferred income tax liabilities:		
Accumulated depreciation and property cost differences	**(930)**	(952)
Deferred fuel recovery	**(55)**	(67)
Income taxes recoverable through future rates	**(317)**	(129)
Investments	**(10)**	(61)
Other	**(27)**	(27)
Total deferred income tax liabilities	**(1,339)**	(1,236)
Total net deferred income tax liabilities	**$(826)**	$(726)

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

(in millions)	**2006**	2005
Current deferred income tax assets, included in prepayments and other current assets	**$34**	$ –
Current deferred income tax liabilities, included in other current liabilities	–	(4)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(860)**	(722)
Total net deferred income tax liabilities	**$(826)**	$(726)

At December 31, 2006 and 2005, PEC had recorded $49 million and $92 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

At December 31, 2006, the federal income tax credit carry forward includes $1 million of general business credits that will expire during the period 2023 through 2025.

At December 31, 2006 and 2005, PEC had recorded $5 million and $2 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

Considering all tax contingency reserves, PEC does not expect the resolution of these matters to have a material impact on its financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

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

	2006	2005	2004
Effective income tax rate	**36.7%**	32.7%	34.1%
State income taxes, net of federal benefit	**(2.3)**	(2.1)	(2.9)
Investment tax credit amortization	**0.8**	1.1	1.1
Domestic manufacturing deduction	**0.6**	0.7	–
Progress Energy tax benefit allocation	–	2.9	3.0
Other differences, net	**(0.8)**	(0.3)	(0.3)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	**2006**	2005	2004
Current – federal	**$285**	$343	$232
– state	**39**	45	33
Deferred – federal	**(42)**	(120)	(18)
– state	**(11)**	(21)	(1)
Investment tax credit	**(6)**	(8)	(7)
Total income tax expense	**$265**	$239	$239

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2006 or 2004.

- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock, interim period vesting of stock-settled PSSP awards and exercises of nonqualified stock options, which was recorded in common stock during 2006. Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with Progress Energy (See Note 1D). PEC's intercompany tax payable was approximately $51 million and $74 million at December 31, 2006 and 2005, respectively.

PEF

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2006**	2005
Deferred income tax assets		
Asset retirement obligation liability	**$9**	$3
Derivative instruments	**30**	–
Environmental remediation liability	**24**	15
Income taxes refundable through future rates	**95**	123
SFAS No. 158, postretirement and pension benefits	**150**	85
Unbilled revenue	**36**	30
Other	**61**	53
Total deferred income tax assets	**405**	309
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(429)**	(401)
Deferred fuel recovery	**(5)**	(21)
Deferred storm costs	**(45)**	(87)
Derivative instruments	**–**	(45)
Income taxes recoverable through future rates	**(119)**	(28)
Investments	**(61)**	(45)
Prepaid pension costs	**(67)**	(61)
Other	**(33)**	(25)
Total deferred income tax liabilities	**(759)**	(713)
Total net deferred income tax liabilities	**$(354)**	$(404)

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

(in millions)	**2006**	2005
Current deferred income tax assets	**$86**	$12
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(440)**	(416)
Total net deferred income tax liabilities	**$(354)**	$(404)

At December 31, 2006 and 2005, PEF had recorded $26 million and $17 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Balance Sheets.

At December 31, 2006 and 2005, respectively, PEF had recorded $5 million and $7 million of tax contingency reserves, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

Considering all tax contingency reserves, PEF does not expect the resolution of these matters to have a material impact on its financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

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

	2006	2005	2004
Effective income tax rate	**37.0%**	31.8%	34.2%
State income taxes, net of federal benefit	**(3.6)**	(3.3)	(3.5)
Investment tax credit amortization	**1.2**	1.4	1.2
Domestic manufacturing deduction	**0.3**	0.9	–
Progress Energy tax allocation benefit	–	3.2	2.5
Other differences, net	**0.1**	1.0	0.6
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	**2006**	2005	2004
Current – federal	**$207**	$146	$55
– state	**34**	25	9
Deferred – federal	**(36)**	(39)	98
– state	**(6)**	(6)	18
Investment tax credit	**(6)**	(5)	(6)
Total income tax expense	**$193**	$121	$174

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2006 or 2004.

- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Statements of Comprehensive Income.

- Less than $1 million of current tax benefit related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2006, 2005 and 2004.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D). PEF's intercompany tax receivable was approximately $47 million at December 31, 2006. PEF's intercompany tax payable was approximately $7 million at December 31, 2005.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The unrealized loss/gain recognized due to these market fluctuations is recorded in other, net on the Consolidated Statements of Income (See Note 20). The liability, included in other liabilities and deferred credits on the Consolidated Balance Sheets, at December 31, 2006 and 2005, was $32 million and $7 million, respectively.

16. BENEFIT PLANS

A. Postretirement Benefits

We have noncontributory defined benefit retirement plans for substantially all full-time employees that provide pension benefits. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

See Note 2 for information related to the implementation of SFAS No. 158 as of December 31, 2006.

COSTS OF BENEFIT PLANS

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of the pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

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

Progress Energy

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$45**	$47	$54	**$9**	$9	$12
Interest cost	**117**	117	110	**33**	33	31
Expected return on plan assets	**(148)**	(147)	(155)	**(6)**	(5)	(5)
Amortization of actuarial loss[a]	**18**	21	6	**4**	6	4
Other amortization, net [a]	**–**	–	(1)	**5**	5	3
Net periodic cost	**$32**	$38	$14	**$45**	$48	$45

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

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

No amounts related to our OPEB plans were recognized as a component of other comprehensive income (OCI) for the years ended December 31, 2006, 2005 and 2004. Pre-tax amounts related to our pension plans recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004 were net actuarial gains (losses) of $78 million, $(41) million and $(202) million, respectively.

PEC

(in millions)	Pension Benefits 2006	2005	2004	Other Postretirement Benefits 2006	2005	2004
Service cost	**$22**	$22	$24	**$4**	$4	$6
Interest cost	**52**	53	52	**17**	17	15
Expected return on plan assets	**(59)**	(62)	(69)	**(4)**	(4)	(4)
Amortization of actuarial loss	**11**	10	1	**2**	5	2
Other amortization, net	**1**	1	–	**1**	1	1
Net periodic cost	**$27**	$24	$8	**$20**	$23	$20

In addition to the net periodic cost reflected above, in 2005, PEC recorded costs for special termination benefits related to a voluntary enhanced retirement program of $21 million for pension benefits and $8 million for other postretirement benefits.

No amounts related to PEC's OPEB plan were recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004. Pre-tax amounts related to PEC's pension plans recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004, were net actuarial gains (losses) of $59 million, $(19) million and $(174) million, respectively.

PEF

(in millions)	Pension Benefits 2006	2005	2004	Other Postretirement Benefits 2006	2005	2004
Service cost	**$16**	$16	$21	**$3**	$3	$4
Interest cost	**49**	48	43	**14**	13	13
Expected return on plan assets	**(78)**	(73)	(73)	**(1)**	(1)	(1)
Amortization of actuarial loss	**3**	8	2	**1**	2	1
Other amortization, net	**(1)**	(1)	(1)	**4**	4	4
Net periodic (benefit) cost	**$(11)**	$(2)	$(8)	**$21**	$21	$21

In addition to the net periodic cost and benefit reflected above, in 2005 PEF recorded costs for special termination benefits related to a voluntary enhanced retirement program of $84 million for pension benefits and $7 million for other postretirement benefits.

No amounts related to PEF's OPEB plans were recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004. No amounts related to PEF's pension plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. For the year ended December 31, 2004, a pre-tax net actuarial gain of $6 million was recognized as a component of OCI.

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

	Pension Benefits 2006	2005	2004	Other Postretirement Benefits 2006	2005	2004
Discount rate	**5.65%**	5.70%	6.30%	**5.65%**	5.70%	6.30%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.00%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.25%	**8.30%**	8.25%	8.50%

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on PEF's OPEB plan assets was 5.0% for all years presented.

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. The Progress Registrants have chosen to use an expected long-term rate of 9.0%, the low end of the range, beginning in 2005.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2006 and 2005 are presented in the tables below, with each table followed by related supplementary information.

Progress Energy

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$2,164**	$1,961	**$650**	$538
Service cost	**45**	47	**9**	9
Interest cost	**117**	117	**33**	33
Benefit payments	**(174)**	(182)	**(29)**	(33)
Plan amendment	**18**	–	**(4)**	–
Special termination benefits	**-**	123	**-**	19
Actuarial (gain) loss	**(47)**	98	**(31)**	84
Obligation at December 31	**2,123**	2,164	**628**	650
Fair value of plan assets at December 31	**1,836**	1,770	**74**	76
Funded status	**$(287)**	$(394)	**$(554)**	$(574)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.123 billion and $2.164 billion at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $2.083 billion and $2.117 billion at December 31, 2006 and 2005, respectively, and plan assets of $1.836 billion and $1.770 billion at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Current liabilities	**$14**	$ –	**$1**	$ –
Noncurrent liabilities	**273**	347	**553**	390

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$49**	$260	**$7**	$–
Other, net	**5**	–	**1**	–
Recognized in regulatory assets, net				
Net actuarial loss (gain)	**215**	83	**108**	(19)
Other, net	**22**	–	**28**	24
Recognized as an intangible asset				
Prior service cost	**–**	23	**–**	–
Not recognized in the Consolidated Balance Sheets				
Net actuarial loss	**–**	47	**–**	170
Other, net	**–**	–	**–**	14
Total not yet recognized as a component of net periodic cost(a)	**$291**	$413	**$144**	$189

(a) All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss (a)	**$15**	**$6**
Amortization of other, net(a)	**2**	**5**

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

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$969**	$928	**$333**	$262
Service cost	**22**	22	**4**	4
Interest cost	**52**	53	**17**	17
Plan amendment	**9**	–	**–**	–
Benefit payments	**(83)**	(94)	**(11)**	(14)
Actuarial (gain) loss	**(17)**	39	**(13)**	56
Special termination benefits	**–**	21	**–**	8
Obligation at December 31	**952**	969	**330**	333
Fair value of plan assets at December 31	**741**	731	**45**	49
Funded status	**$(211)**	$(238)	**$(285)**	$(284)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $952 million and $969 million at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $946 million and $963 million at December 31, 2006 and 2005, respectively, and plan assets of $741 million and $731 million at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Current liabilities	**$2**	$ –	**$ –**	$ –
Noncurrent liabilities	**209**	232	**285**	189

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$–**	$195	**$–**	$–
Recognized as an intangible asset				
Prior service cost	**–**	17	**–**	–
Recognized in regulatory assets				
Net actuarial loss	**142**	–	**69**	–
Other, net	**25**	–	**7**	–
Not recognized in the Consolidated Balance Sheets				
Net actuarial loss	**–**	6	**–**	87
Other, net	**–**	–	**–**	8
Total not yet recognized as a component of net periodic cost	**$167**	$218	**$76**	$95

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$11**	**$4**
Amortization of other, net	**2**	**1**

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$896**	$767	**$259**	$232
Service cost	**16**	16	**3**	3
Interest cost	**49**	48	**14**	13
Plan amendment	**8**	–	**(4)**	–
Benefit payments	**(69)**	(61)	**(17)**	(18)
Special termination benefits	**-**	85	**-**	7
Actuarial (gain) loss	**(20)**	41	**(9)**	22
Obligation at December 31	**880**	896	**246**	259
Fair value of plan assets at December 31	**952**	895	**24**	22
Funded status	**$72**	$(1)	**$(222)**	$(237)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $342 million and $341 million at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $311 million and $306 million at December 31, 2006 and 2005, respectively, and plan assets of $240 million and $217 million at December 31, 2006 and 2005, respectively. The total accumulated benefit obligation for pension plans was $849 million and $860 million at December 31, 2006 and 2005, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Noncurrent assets	**$174**	$200	**$ –**	$ –
Current liabilities	**3**	–	**–**	–
Noncurrent liabilities	**99**	89	**222**	159

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Recognized as an intangible asset				
Prior service cost	**$–**	$1	**$–**	$–
Recognized in regulatory assets, net				
Net actuarial loss	**72**	7	**39**	–
Other, net	**(2)**	–	**21**	–
Not recognized in the Balance Sheets				
Net actuarial loss	**–**	125	**–**	49
Other, net	**–**	(13)	**–**	29
Total not yet recognized as a component of net periodic cost	**$70**	$120	**$60**	$78

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss	**$1**	**$1**
Amortization of other, net	**(1)**	**4**

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

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
Discount rate	**5.95%**	5.65%	**5.95%**	5.65%
Rate of increase in future compensation				
Bargaining	**4.25%**	3.50%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**9.00%**	8.25%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**9.00%**	8.25%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2014**	2013

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable. The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			
Effect on total of service and interest cost	$2	$1	$1
Effect on postretirement benefit obligation	29	15	11
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(1)	(1)	(1)
Effect on postretirement benefit obligation	(22)	(12)	(9)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 30 percent for PEC and 10 percent for PEF. The OPEB benefits payments for 2006 are also reduced by prescription drug-related federal subsidies received, which totaled $2 million for us, $1 million for PEC and $1 million for PEF.

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

Progress Energy	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$1,770**	$1,774	**$76**	$70
Actual return on plan assets	**222**	170	**8**	5
Benefit payments	**(174)**	(182)	**(29)**	(33)
Employer contributions	**18**	8	**19**	34
Fair value of plan assets at December 31	**$1,836**	$1,770	**$74**	$76

PEC	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$731**	$753	**$49**	$45
Actual return on plan assets	**91**	71	**6**	4
Benefit payments	**(83)**	(94)	**(11)**	(14)
Employer contributions	**2**	1	**1**	14
Fair value of plan assets at December 31	**$741**	$731	**$45**	$49

PEF

(in millions)	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
Fair value of plan assets at January 1	**$895**	$868	**$22**	$20
Actual return on plan assets	**114**	85	**1**	–
Benefit payments	**(69)**	(61)	**(17)**	(18)
Employer contributions	**12**	3	**18**	20
Fair value of plan assets at December 31	**$952**	$895	**$24**	$22

The asset allocation for the benefit plans at the end of 2006 and 2005 and the target allocation for the plans, by asset category, are presented in the following tables. The pension benefit plan allocations and targets are consistent for all Progress Registrants.

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Equity – domestic	40%	**44%**	44%
Equity – international	15%	**23%**	22%
Debt – domestic	20%	**12%**	13%
Debt – international	10%	**9%**	8%
Other	15%	**12%**	13%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Equity – domestic	27%	**30%**	32%
Equity – international	10%	**15%**	16%
Debt – domestic	46%	**40%**	37%
Debt – international	7%	**7%**	6%
Other	10%	**8%**	9%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Equity – domestic	40%	**44%**	44%
Equity – international	15%	**23%**	22%
Debt – domestic	20%	**12%**	13%
Debt – international	10%	**9%**	8%
Other	15%	**12%**	13%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Debt – domestic	100%	**100%**	100%

For pension plan assets and a substantial portion of OPEB plan assets, the Progress Registrants set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus five percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2007, we expect to make $60 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $143, $147, $151, $154, $154 and $838, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $41, $45, $48, $51, $53 and $284, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $3, $4, $4, $5, $5 and $38, respectively.

In 2007, PEC expects to make $35 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $69, $72, $74, $76, $75 and $399, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $19, $21, $23, $25, $27, and $148, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $1, $2, $2, $2, $3 and $19, respectively.

In 2007, PEF expects to make $10 million of contributions directly to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $56, $56, $57, $57, $59 and $316, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $19, $20, $21, $22, $22 and $113, 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 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $2, $2, $2, $2, $2 and $16, respectively.

B. Florida Progress Acquisition

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

As discussed in Note 3, on December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of PVI's remaining CCO physical and commercial assets and on July 12, 2006, our board of directors approved a plan to divest of Gas. The transaction to sell Gas closed on October 2, 2006. We expect to complete the disposition plan for CCO in 2007.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 Bcf of natural gas would be fulfilled. Therefore, these contracts were no longer treated as cash flow hedges, and were dedesignated and cash flow hedge accounting was discontinued.

At December 31, 2006, derivative assets and derivative liabilities related to CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. At December 31, 2005, derivative assets and derivative liabilities related to Gas and CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. For the years ending December 31, 2006, 2005 and 2004, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ending December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2004, discontinued operations, net of tax includes $10 million in after-tax deferred losses, which were reclassified to earnings due to discontinuance of the related cash flow hedges.

A. Commodity Derivatives

GENERAL

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

In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2006 and 2005, the remaining liability was $14 million and $19 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our or the Utilities' results of operations during the years ended December 31, 2006, 2005 and 2004. Excluding $107 million of derivative assets, which are included in assets of discontinued operations on the Consolidated Balance Sheet and $31 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2006, we did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment at PEF, as discussed below. Our discontinued operations did not have material outstanding positions in such contracts at December 31, 2005.

PEC did not have material outstanding positions in such contracts at December 31, 2006 and 2005. PEF did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment, as discussed below.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2006, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits, an $87 million short-term derivative liability position included in other current liabilities and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $49 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts will be marked-to-market with changes in fair value recorded through earnings from synthetic fuels production.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities' results of operations for 2006, 2005 and 2004.

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

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Fair value of assets	**$2**	$7	**$2**	$7	**$–**	$–
Fair value of liabilities	**–**	(4)	**–**	(4)	**–**	–
Fair value, net	**$2**	$3	**$2**	$3	**$–**	$–

Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. Excluded from the table above are $163 million of derivative assets, which are included in assets of discontinued operations, and $54 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2005.

At December 31, 2006, the amount recorded in our, PEC's or PEF's AOCI related to commodity cash flow hedges was not material. At December 31, 2005, we had $69 million of after-tax deferred income and PEC had $2 million of after-tax deferred income recorded in AOCI related to commodity cash flow hedges. PEF had no amount recorded in AOCI related to commodity cash flow hedges at December 31, 2006 or 2005.

B. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

The fair values of open interest rate hedges at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Interest rate cash flow hedges	**$(2)**	$1	**$(1)**	$–	**$(1)**	$–
Interest rate fair value hedges	**(1)**	(2)	**–**	–	**–**	–

CASH FLOW HEDGES

Gains and losses from cash flow hedges are recorded in AOCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in AOCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our or the Utilities' results of operations for 2006, 2005 and 2004.

The following table presents selected information related to interest rate cash flow hedges included in AOCI at December 31, 2006:

	Maximum Term			Accumulated Other Comprehensive Loss, net of Tax[a]			Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]		
(term in years/ dollars in millions)	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Interest rate cash flow hedges	1	1	1	$(14)	$(5)	$(1)	$(2)	$(1)	$–

[a] Includes amounts related to terminated hedges.

[b] Actual amounts that will be reclassified to earnings may vary from the expected amounts presented above as a result of changes in interest rates.

PEC entered into a $50 million forward starting swap on June 2, 2006, and PEF entered into a $50 million forward starting swap on June 6, 2006, to mitigate exposure to interest rate risk on their respective anticipated debt issuances in 2007. These swaps were designated as cash flow hedges as of July 1, 2006.

At December 31, 2005, including amounts related to terminated hedges, we had $13 million of after-tax deferred losses and PEC had $5 million of after-tax deferred losses recorded in AOCI related to interest rate cash flow hedges. PEF had no amount recorded in AOCI related to interest rate cash flow hedges.

At December 31, 2005, we had $100 million notional of interest rate cash flow hedges, which were settled in the first quarter of 2006. The Utilities had no open interest rate cash flow hedges at December 31, 2005.

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, 2006 and 2005, we had

$50 million notional and $150 million notional, respectively, of interest rate fair value hedges. At December 31, 2006 and 2005, the Utilities had no open interest rate fair value hedges.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, the Parent had issued $1.34 billion of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. The repeal of PUHCA 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Balance Sheets.

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2006, 2005 and 2004 to PEC amounted to $188 million, $202 million and $209 million, respectively, and services provided to PEF were $165 million, $169 million and $165 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2006, 2005 and 2004 amounted to $34 million, $54 million and $52 million, respectively. Services provided by PEF to PEC during 2006, 2005 and 2004 amounted to $8 million, $14 million and $16 million, respectively.

PEC and PEF participate in an internal money pool, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is also used to settle intercompany balances. The weighted-average interest rate for the money pool was 5.17%, 3.77% and 1.72% at December 31, 2006, 2005 and 2004, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded insignificant interest expense related to the money pool for all the years presented.

Progress Fuels sold coal to PEF at cost in 2006 and for an insignificant profit in 2005 and 2004. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $321 million, $402 million and $331 million for the years ended December 31, 2006, 2005 and 2004, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

PEC and its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 14).

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are: PEC, PEF, and Coal and Synthetic Fuels.

Our PEC and PEF business segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. These electric operations also distribute and sell electricity to other utilities, primarily in the eastern United States.

Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties, and coal terminal services. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding synthetic fuels production. During September and October 2006, we resumed limited synthetic fuels production at our facilities, which continued through the end of 2006. See Notes 8 and 9 for additional information.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC as well as other nonregulated businesses. These nonregulated businesses do not separately meet the disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that our subsidiary Strategic Resource Solutions Corp. reached with the San Francisco United School District related to civil proceedings. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

As discussed in Note 3, prior to 2006, our former Progress Ventures segment was engaged in nonregulated electric generation and energy marketing activities and natural gas drilling and production. Also, prior to 2006, PT LLC was included within the Corporate and Other segment, and Dixie Fuels and other fuels business were included within the Coal and Synthetic Fuels segment. In connection with their respective divestitures, certain of which are expected to close in 2007, these operations were reclassified to discontinued operations in 2006 and therefore are not included in the results from continuing operations during the periods reported. For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the Coal and Synthetic Fuels segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2006, 2005 and 2004 were not significant. Prior to 2006, income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA 1935, the Parent stopped allocating these tax benefits in 2006.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments. Operational results and assets of discontinued operations are not included in the table presented below.

(in millions)	PEC	PEF	Coal and Synthetic Fuels	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2006						
Revenues						
Unaffiliated	**$4,086**	**$4,639**	**$845**	**$ –**	**$ –**	**$9,570**
Intersegment	**–**	**–**	**321**	**408**	**(729)**	**–**
Total revenues	**4,086**	**4,639**	**1,166**	**408**	**(729)**	**9,570**
Depreciation and amortization	**571**	**404**	**19**	**38**	**–**	**1,032**
Interest income	**25**	**15**	**2**	**85**	**(66)**	**61**
Total interest charges, net	**215**	**150**	**15**	**312**	**(67)**	**625**
Impairment of long-lived assets and investments	**–**	**–**	**91**	**–**	**–**	**91**
Income tax expense (benefit)	**265**	**193**	**(145)**	**(109)**	**–**	**204**
Segment profit (loss)	**454**	**326**	**(76)**	**(190)**	**–**	**514**
Total assets	**12,020**	**8,593**	**268**	**15,204**	**(11,271)**	**24,814**
Capital and investment expenditures	**808**	**741**	**3**	**12**	**(9)**	**1,555**
As of and for the year ended December 31, 2005						
Revenues						
Unaffiliated	$3,991	$3,955	$1,222	$ –	$ –	$9,168
Intersegment	–	–	402	437	(839)	–
Total revenues	3,991	3,955	1,624	437	(839)	9,168
Depreciation and amortization	561	334	34	34	–	963
Interest income	8	1	3	94	(90)	16
Total interest charges, net	192	126	23	318	(85)	574
Postretirement and severance charges	55	102	5	1	–	163
Income tax expense (benefit)	239	121	(354)	(43)	–	(37)
Segment profit (loss)	490	258	163	(190)	–	721
Total assets	11,502	8,318	450	17,898	(13,672)	24,496
Capital and investment expenditures	682	543	5	19	(19)	1,230

(in millions)	PEC	PEF	Coal and Synthetic Fuels	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2004						
Revenues						
Unaffiliated	$3,629	$3,525	$886	$13	$ –	$8,053
Intersegment	–	–	333	430	(763)	–
Total revenues	3,629	3,525	1,219	443	(763)	8,053
Depreciation and amortization	570	281	34	34	–	919
Interest income	4	–	6	90	(89)	11
Total interest charges, net	192	114	23	322	(85)	566
Postretirement and severance charges	2	–	1	–	–	3
Income tax expense (benefit)	239	174	(280)	(66)	–	67
Segment profit (loss)	458	333	90	(208)	–	673
Total assets	10,787	7,924	540	17,465	(13,550)	23,166
Capital and investment expenditures	620	492	6	20	(12)	1,126

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments, and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the accompanying Statements of Income for the years ended December 31 were as follows:

Progress Energy

(in millions)	**2006**	2005	2004
Other income			
Nonregulated energy and delivery services income	**$41**	$32	$28
DIG Issue C20 amortization (Note 17A)	**5**	7	9
Contingent value obligation unrealized gain (Note 15)	**–**	6	9
Gain on sale of Level 3 stock [(a)]	**32**	–	–
Investment gains	**4**	4	2
Income from equity investments	**1**	1	3
AFUDC equity	**21**	16	12
Reversal of indemnification liability (Note 21B)	**29**	–	–
Other	**16**	16	14
Total other income	**149**	82	77
Other expense			
Nonregulated energy and delivery services expenses	**27**	23	21
Donations	**20**	18	15
Contingent value obligation unrealized loss (Note 15)	**25**	–	–
Loss from equity investments	**8**	13	8
Loss on debt redemption[(b)]	**59**	–	–
FERC audit settlement	**–**	7	–
Indemnification liability (Note 21B)	**13**	16	–
Other	**15**	12	29
Total other expense	**167**	89	73
Other, net – Progress Energy	**$(18)**	$(7)	$4

PEC

(in millions)	**2006**	2005	2004
Other income			
Nonregulated energy and delivery services income	**$15**	$12	$11
DIG Issue C20 amortization (Note 17A)	**5**	7	9
Income from equity investments	**–**	1	3
AFUDC equity	**4**	3	4
Reversal of indemnification liability (Note 21B)	**29**	–	–
Other	**10**	9	13
Total other income	**63**	32	40
Other expense			
Nonregulated energy and delivery services expenses	**7**	9	9
Donations	**10**	8	7
Losses from equity investments	**1**	–	3
FERC audit settlement	**–**	4	–
Indemnification liability (Note 21B)	**13**	16	–
Other	**7**	10	22
Total other expense	**38**	47	41
Other, net – PEC	**$25**	$(15)	$(1)

PEF

(in millions)	**2006**	2005	2004
Other income			
Nonregulated energy and delivery services income	**$26**	$20	$17
Investment gains	**2**	2	1
AFUDC equity	**17**	13	7
Other	**1**	–	–
Total other income	**46**	35	25
Other expense			
Nonregulated energy and delivery services expenses	**20**	14	12
Donations	**10**	10	9
Losses from equity investments	**1**	–	–
FERC audit settlement	–	3	–
Other	**2**	1	1
Total other expense	**33**	28	22
Other, net – PEF	**$13**	$7	$3

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3D). These gains are prior to the consideration of minority interest.

(b) On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

21. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. Hazardous and Solid Waste

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida, as described below in greater detail. Various materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. We measure our liability for these sites based on available evidence including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	**2006**	2005
PEC		
MGP and other sites[a]	**$22**	$7
PEF		
Remediation of distribution and substation transformers	**43**	20
MGP and other sites	**18**	18
Total PEF environmental remediation accruals[b]	**61**	38
Progress Energy nonregulated operations	**3**	3
Total Progress Energy environmental remediation accruals	**$86**	$48

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

Progress Energy

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, our environmental sites include the following related to our nonregulated operations.

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. At December 31, 2006 and 2005, the remaining accrual balance was approximately $3 million. Expenditures related to this liability were not material during 2006 and 2005.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2006, including the Ward Transformer site and MGP sites discussed below, PEC accrued approximately $21 million and spent approximately $6 million. For the year ended December 31, 2005, PEC accrued approximately $4 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses (See Note 7B).

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $32 million. In May 2006, a meeting was called by the EPA to discuss a settlement proposal among the PRPs. An agreement among PRPs has not been reached; consequently, it is not possible at this time to reasonably estimate the amount of PEC's share of the reimbursement for remediation of the Carolina Transformer site. The outcome of this matter cannot be predicted.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for EPA's past expenditures in addressing conditions at the site. In September 2005, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2005, PEC accrued approximately $3 million for its portion of the EPA's estimated remediation costs and the EPA's past costs. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. However, the maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience.

PEF

PEF has received approval from the FPSC for recovery of the majority of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the years ended December 31, 2006 and 2005, PEF accrued approximately $42 million and $2 million, respectively, due to additional sites expected to require remediation and spent approximately $19 million and $9 million, respectively, related to the remediation of transformers. At December 31, 2006, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures and insurance proceeds were not material to our or PEF's results of operations or financial condition. For the year ended December 31, 2005, PEF made no material accruals, spent approximately $1 million and received approximately $1 million of additional insurance proceeds.

B. Air and Water Quality

We are subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations include the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and the Clean Smokestacks Act. At December 31, 2006, cumulative capital expenditures to date to comply with these environmental laws and regulations were $937 million, including $909 million and $28 million at PEC and PEF, respectively.

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and SO_2 from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. For the years ended December 31, 2006, 2005 and 2004, PEC recognized amortization of $140 million, $147 million and $174 million, respectively, and has recognized $535 million in cumulative amortization through December 31, 2006. The remaining amortization requirement of $34 million will be recorded during the one-year period ending December 31, 2007. The NCUC will hold a hearing prior to December 31, 2007, to determine cost-recovery amounts for 2008 and 2009.

Two of PEC's largest coal-fired generation plants (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance on the jointly owned units, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2006, the amount of the liability was $29 million and had increased from $16 million at December 31, 2005, based upon the respective current estimates for Clean Smokestacks Act compliance. Because PEC has taken a systemwide compliance approach, its North Carolina retail customers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail customers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On November 2, 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and subsequently reclassified $29 million of indemnification expense to Clean Smokestacks Act amortization (See Note 20).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2006, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$2,128	$1,514	$1,057	$509	$390	$1,251
Purchased power	485	454	422	377	381	4,165
Construction obligations	393	197	8	3	–	–
Other purchase obligations	86	71	23	22	15	74
Total	$3,092	$2,236	$1,510	$911	$786	$5,490

PEC

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$1,008	$759	$547	$314	$231	$647
Purchased power	129	87	85	43	44	464
Construction obligations	99	9	–	–	–	–
Other purchase obligations	21	22	3	3	3	12
Total	$1,257	$877	$635	$360	$278	$1,123

PEF

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$931	$682	$511	$194	$160	$605
Purchased power	356	366	336	334	337	3,701
Construction obligations	294	188	8	3	–	–
Other purchase obligations	46	46	20	19	12	62
Total	$1,627	$1,282	$875	$550	$509	$4,368

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.168 billion, $3.071 billion and $2.033 billion for 2006, 2005 and 2004, respectively. PEC's total payments under these commitments for its generating plants were $1.051 billion, $964 million and $477 million in 2006, 2005 and 2004, respectively. PEF's payments totaled $577 million, $506 million and $375 million in 2006, 2005 and 2004, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2007 to 2033. These purchased power contracts generally provide for capacity and energy payments.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and Power Agency, PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, Harris. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in Harris, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity and energy costs, total approximately $34 million. These contractual purchases totaled $38 million, $37 million and $39 million for 2006, 2005 and 2004, respectively.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $80 million, $71 million and $62 million for 2006, 2005 and 2004, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $40 million, $44 million and $42 million in 2006, 2005 and 2004, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 327 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $182 million, $112 million and $90 million in 2006, 2005 and 2004, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $162 million, $175 million and $128 million for 2006, 2005 and 2004, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $65 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 943 MW of capacity with expiration dates ranging from 2007 to 2033. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $277 million, $262 million and $247 million for 2006, 2005 and 2004, respectively. At December 31, 2006, minimum expected future capacity payments under these contracts were $289 million, $300 million, $271 million, $274 million and $288 million for 2007 through 2011, respectively, and $3.508 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $3.9 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

In January 2006, PEF entered into a conditional contract with Gulfstream Natural Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008 through January 1, 2031. The total cost to PEF associated with this agreement is approximately $777 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc. for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $877 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million. The transaction is subject to several conditions precedent, including Florida Public Service Commission approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $128 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $365 million, $91 million and $108 million for 2006, 2005 and 2004, respectively. At December 31, 2006, PEC had construction obligations related to Clean Smokestacks Act capital projects of $99 million and $9 million for 2007 and 2008, respectively, and none thereafter. Total purchases by PEC under various capital projects related to Clean Smokestacks Act were $225 million for 2006 and purchases under various combustion turbine construction obligations were $5 million for 2004. PEC did not have any purchases related to construction obligations in 2005. PEF has purchase obligations related to various plant capital projects related to new generation and Florida CAIR. Total payments under PEF's contracts were $140 million, $91 million and $102 million for 2006, 2005 and 2004, respectively. PEF's future obligations under these contracts are $294 million, $188 million, $8 million and $3 million for 2007 through 2010, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $91 million, $82 million and $44 million for 2006, 2005 and 2004, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $18 million, $17 million and $15 million for 2006, 2005 and 2004, respectively. Estimated future payments under these contracts of $198 million are not reflected in the table presented at the beginning of this footnote. Included in these contracts are purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these agreements were $16 million, $15 million and $13 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are approximately $13 million for 2007, $12 million for 2008 through 2011 and approximately $76 million payable thereafter. We anticipate transferring the obligations under these contracts to a third party as part of our disposition strategy.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $2 million, $10 million and $2 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $21 million each for 2007 and 2008, $3 million each for 2009 through 2011 and $12 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006, $13 million for 2005 and $17 million for 2004. We do not have any future purchase obligations under these contracts.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $12 million, $8 million and $11 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $11 million, $16 million, $14 million, $19 million and $12 million for 2007 through 2011, respectively, with approximately $62 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $21 million for 2006 and $34 million for 2005. There were no payments under these contracts during 2004. Future obligations under these contracts are $22 million, $8 million and $6 million for 2007 through 2009, respectively.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $42 million for 2006 and $38 million each for 2005 and 2004. Our purchased power expense under agreements classified as operating leases was approximately $60 million, $14 million and $25 million in 2006, 2005 and 2004, respectively.

PEC's rent expense under operating leases totaled $25 million for 2006, $24 million for 2005 and $20 million for 2004. These amounts include rent expense allocated from PESC of $8 million, $7 million and $10 million for 2006, 2005 and 2004, respectively. Purchased power expense under agreements classified as operating leases were approximately $10 million, $11 million and $25 million in 2006, 2005 and 2004, respectively.

PEF's rent expense under operating leases totaled $16 million, $11 million and $14 million during 2006, 2005 and 2004, respectively. These amounts include rent expense allocated from PESC to PEF of $7 million each for 2006 and 2005 and $10 million for 2004. Purchased power expense under agreements classified as operating leases was approximately $49 million and $3 million in 2006 and 2005, respectively, and none in 2004.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2006**	2005	**2006**	2005	**2006**	2005
Buildings	**$84**	$30	**$30**	$30	**$54**	$–
Less: Accumulated amortization	**(12)**	(12)	**(12)**	(12)	**–**	–
Total	**$72**	$18	**$18**	$18	**$54**	$–

At December 31, 2006, 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
2007	$6	$79	$2	$36	$4	$39
2008	8	63	3	30	5	29
2009	7	55	2	30	5	22
2010	8	40	3	18	5	20
2011	7	19	2	13	5	4
Thereafter	91	172	12	142	79	26
Minimum annual payments	127	$428	24	$269	103	$140
Less amount representing imputed interest	(55)		(6)		(49)	
Present value of net minimum lease payments under capital leases	$72		$18		$54	

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2005, PEF entered into an agreement for a new capital lease for a building completed during 2006. The lease term expires March 2047 and provides for annual payments of approximately $5 million from 2007 through 2026 for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in the Statements of Income.

In 2006, PEF extended the terms of an agreement for purchased power, which is classified as a capital lease, for an additional 10 years. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until 2007. Therefore this capital lease is not included in the table above. The agreement calls for annual payments of approximately $27 million from 2007 through 2024 for a total of approximately $460 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $9 million, $7 million, $6 million, $4 million and $2 million for 2007 through 2011, respectively. Rents received under these operating leases totaled $9 million, $8 million and $6 million for 2006, 2005 and 2004, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2007 and none thereafter. PEC's rents received are contingent upon usage and totaled $31 million each for 2006 and 2005 and $32 million for 2004. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $72 million for 2006 and $63 million each for 2005 and 2004. PEF's minimum rentals under noncancelable leases are not material for 2007 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 18). Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Balance Sheets.

At December 31, 2006, 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. Related to the sales of businesses, the latest notice period extends until 2012 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2006, the maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $208 million, including $32 million at PEF. At December 31, 2006 and 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $60 million and $41 million, respectively. These amounts include $29 million and $16 million, respectively, for PEC at December 31, 2006 and 2005, and $8 million for PEF at December 31, 2006. PEF had no liabilities related to guarantees and indemnifications to third parties at December 31, 2005. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. Other Commitments and Contingencies

1. Spent Nuclear Fuel Matters

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level radioactive waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been or are expected to be presented in the trials or appeals that are currently scheduled to occur during 2006 and 2007. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006. The trial court lifted the stay on March 22, 2006, and discovery has commenced. The trial court's scheduling order, issued on March 23, 2006, included an anticipated trial date in late 2007.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The EPA is expected to issue a new safety standard for the repository in early 2007. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and has since reported that the license application will be submitted by June 2008. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE requested $545 million for fiscal year 2007. The request has not been approved at this time and the DOE is operating under a continuing resolution that limits spending to the level of fiscal year 2006.The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation of onsite dry cask storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license extensions, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

2. Synthetic Fuels Matters

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted that (1) pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities and (2) it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.*, asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. The parties are currently engaged in discovery in the Florida Global Case.

The second suit, *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC*, was filed by the Progress Affiliates in the Superior Court for Wake County, N.C., seeking declaratory relief consistent with our interpretation of the Asset Purchase Agreement (the North Carolina Global Case). Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow during the course of the Internal Revenue Service (IRS) audit of the Earthco synthetic fuels facilities. The audit was successfully resolved in 2006 and the escrow, which totaled $42 million at December 31, 2006, was paid to Global in January 2007. The remainder of the suit continues. We cannot predict the outcome of this matter.

3. Other Litigation Matters

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

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing \$300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. \$300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the \$300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of \$25 per share plus all accrued and unpaid dividends thereon to the date of payment. The yearly interest expense is \$21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2006, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of \$300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of CCO, Gas, PT LLC, DeSoto, Rowan, Dixie Fuels and other fuels businesses as discontinued operations as described in Note 3.

Condensed Consolidating Statement of Income
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$4,637	$4,085	$8,722
Diversified business	–	839	9	848
Total operating revenues	–	5,476	4,094	9,570
Operating expenses				
Utility				
Fuel used in electric generation	–	1,835	1,173	3,008
Purchased power	–	766	334	1,100
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	404	605	1,009
Taxes other than on income	–	309	191	500
Other	–	(2)	(1)	(3)
Diversified business				
Cost of sales	–	854	44	898
Depreciation and amortization	–	13	10	23
Impairment of assets	–	44	47	91
Other	–	36	16	52
Total operating expenses	14	4,943	3,304	8,261
Operating (loss) income	(14)	533	790	1,309
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	184	165	625
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	404	646	727
Income tax (benefit) expense	(123)	90	237	204
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	579	305	(370)	514
Discontinued operations, net of tax	(8)	392	(327)	57
Net income (loss)	$571	$697	$(697)	$571

Condensed Consolidating Statement of Income
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,955	$3,990	$7,945
Diversified business	–	1,244	(21)	1,223
Total operating revenues	–	5,199	3,969	9,168
Operating expenses				
Utility				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	334	588	922
Taxes other than on income	4	279	177	460
Other	–	(26)	(11)	(37)
Diversified business				
Cost of sales	–	1,267	86	1,353
Depreciation and amortization	–	21	20	41
Other	–	19	13	32
Total operating expenses	16	4,763	3,169	7,948
Operating (loss) income	(16)	436	800	1,220
Other income (expense), net	66	(5)	(52)	9
Interest charges, net	300	166	108	574
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(250)	265	640	655
Income tax (benefit) expense	(63)	(70)	96	(37)
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' loss, net of tax	–	29	–	29
Income (loss) from continuing operations	697	364	(340)	721
Discontinued operations, net of tax	–	10	(35)	(25)
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

Condensed Consolidating Statement of Income
Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,525	$3,628	$7,153
Diversified business	–	895	5	900
Total operating revenues	–	4,420	3,633	8,053
Operating expenses				
Utility				
Fuel used in electric generation	–	1,175	836	2,011
Purchased power	–	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	–	281	597	878
Taxes other than on income	(2)	254	173	425
Other	–	(2)	(11)	(13)
Diversified business				
Cost of sales	–	911	81	992
Depreciation and amortization	–	21	20	41
Other	–	46	58	104
Total operating expenses	8	3,883	2,890	6,781
Operating (loss) income	(8)	537	743	1,272
Other income (expense), net	65	(4)	(46)	15
Interest charges, net	295	152	119	566
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(238)	381	578	721
Income tax (benefit) expense	(57)	12	112	67
Equity in earnings of consolidated subsidiaries	940	–	(940)	–
Minority interest in subsidiaries' loss, net of tax	–	19	–	19
Income (loss) from continuing operations	759	388	(474)	673
Discontinued operations, net of tax	–	86	–	86
Net income (loss)	$759	$474	$(474)	$759

Condensed Consolidating Balance Sheet
December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$6,337	$8,908	$15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets of discontinued operations	–	45	842	887
Other current assets	27	1,109	1,030	2,166
Total current assets	259	1,231	2,095	3,585
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,583	1,507	3,216
Total deferred debits and other assets	10,866	1,584	(5,579)	6,871
Total assets	$11,125	$9,152	$5,424	$25,701
Capitalization				
Common stock equity	$8,286	$2,708	$(2,708)	$8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities of discontinued operations	–	13	176	189
Other current liabilities	210	1,281	814	2,305
Total current liabilities	210	1,495	1,113	2,818
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	245	306
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	559	1,261	1,853
Total deferred credits and other liabilities	47	2,088	3,524	5,659
Total capitalization and liabilities	$11,125	$9,152	$5,424	$25,701

Condensed Consolidating Balance Sheet
December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$5,821	$8,621	$14,442
Current assets				
Cash and cash equivalents	239	239	127	605
Short-term investments	–	–	191	191
Notes receivable from affiliated companies	467	–	(467)	–
Deferred fuel cost	–	341	261	602
Assets of discontinued operations	–	757	1,809	2,566
Other current assets	22	992	1,029	2,043
Total current assets	728	2,329	2,950	6,007
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	–	(11,594)	–
Goodwill	–	2	3,653	3,655
Other assets and deferred debits	259	1,561	1,138	2,958
Total deferred debits and other assets	11,853	1,563	(6,803)	6,613
Total assets	$12,581	$9,713	$4,768	$27,062
Capitalization				
Common stock equity	$8,038	$3,039	$(3,039)	$8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	31	5	36
Long-term debt, affiliate	–	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,180	522	18,613
Current liabilities				
Current portion of long-term debt	404	109	–	513
Notes payable to affiliated companies	–	315	(315)	–
Short-term debt	–	102	73	175
Liabilities of discontinued operations	–	226	316	542
Other current liabilities	245	762	812	1,819
Total current liabilities	649	1,514	886	3,049
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	–	198	198
Regulatory liabilities	–	1,189	1,338	2,527
Accrued pension and other benefits	12	307	546	865
Other liabilities and deferred credits	9	523	1,278	1,810
Total deferred credits and other liabilities	21	2,019	3,360	5,400
Total capitalization and liabilities	$12,581	$9,713	$4,768	$27,062

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,015	$(398)	$1,912
Investing activities				
Gross utility property additions	–	(718)	(705)	(1,423)
Diversified business property additions	–	(2)	–	(2)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,239	415	1,654
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	561	(1,033)	271
Financing activities				
Issuance of common stock	185	–	–	185
Proceeds from issuance of long-term debt, net	397	–	–	397
Net decrease in short-term debt	–	(102)	(73)	(175)
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Changes in advances from affiliates	–	(243)	243	–
Cash distributions to minority interests of consolidated subsidiary	–	(79)	–	(79)
Other financing activities	(8)	71	(52)	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Cash provided (used) by discontinued operations				
Operating activities	–	92	(6)	86
Investing activities	–	(139)	(2)	(141)
Financing activities	–	–	–	–
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$153	$40	$72	$265

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$409	$509	$1,175
Investing activities				
Gross utility property additions	–	(496)	(584)	(1,080)
Diversified business property additions	–	(6)	–	(6)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	1	(37)
Net cash provided (used) by investing activities	690	(108)	(1,496)	(914)
Financing activities				
Issuance of common stock	208	–	–	208
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Net increase in short-term debt	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	53	(10)	34
Net cash (used) provided by financing activities	(713)	30	912	229
Cash provided (used) by discontinued operations				
Operating activities	–	93	201	294
Investing activities	–	(206)	(26)	(232)
Financing activities	–	(2)	–	(2)
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$239	$239	$127	$605

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$653	$469	$287	$1,409
Investing activities				
Gross utility property additions	–	(482)	(516)	(998)
Diversified business property additions	–	(6)	–	(6)
Nuclear fuel additions	–	–	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	343	29	372
Purchases of available-for-sale securities and other investments	–	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	–	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	–
Contributions to consolidated subsidiaries	(15)	–	15	–
Other investing activities	–	(23)	(7)	(30)
Net cash provided (used) by investing activities	12	(173)	(488)	(649)
Financing activities				
Issuance of common stock	73	–	–	73
Proceeds from issuance of long-term debt, net	365	56	–	421
Net increase in short-term debt	170	293	217	680
Retirement of long-term debt	(705)	(68)	(339)	(1,112)
Dividends paid on common stock	(558)	–	–	(558)
Dividends paid to parent	–	(340)	340	–
Changes in advances from affiliates	–	(205)	205	–
Contributions from parent	–	12	(12)	–
Other financing activities	(5)	15	1	11
Net cash (used) provided by financing activities	(660)	(237)	412	(485)
Cash provided (used) by discontinued operations				
Operating activities	–	145	46	191
Investing activities	–	(190)	(9)	(199)
Financing activities	–	(5)	(241)	(246)
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	–	14	20	34
Cash and cash equivalents at end of year	$5	$23	$27	$55

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First [a][b]	Second [a][b]	Third [a][b]	Fourth [a][b]
2006				
Operating revenues	**$2,223**	**$2,298**	**$2,776**	**$2,273**
Operating income	**268**	**210**	**557**	**274**
Income from continuing operations	**85**	**19**	**283**	**127**
Net income (loss)	**45**	**(47)**	**319**	**254**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.13**	**0.51**
Net income (loss)	**0.18**	**(0.19)**	**1.27**	**1.01**
Diluted earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.12**	**0.51**
Net income (loss)	**0.18**	**(0.19)**	**1.27**	**1.01**
Dividends declared per common share	**0.605**	**0.605**	**0.605**	**0.610**
Market price per share – High	**45.31**	**45.16**	**46.22**	**49.55**
– Low	**42.54**	**40.27**	**42.05**	**44.40**
2005				
Operating revenues	$2,051	$2,079	$2,743	$2,295
Operating income	237	119	539	325
Income from continuing operations before cumulative effect of change in accounting principle	103	2	457	159
Net income (loss)	93	(1)	450	155
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.82	0.62
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.81	0.62
Dividends declared per common share	0.590	0.590	0.590	0.605
Market price per share – High	45.33	45.83	46.00	45.50
– Low	40.63	40.61	41.90	40.19

[a] Operating results have been restated for discontinued operations.
[b] Certain amounts have been reclassified to conform to current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. The first quarter of 2005 included $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative at PEF; the second and fourth quarters of 2005 included reversals of estimated severance expense of $13 million each quarter. The second quarter of 2005 included a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A). The second quarter of 2006 includes a $91 million impairment charge to our synthetic fuels assets and a portion of our coal terminal assets (See Notes 8 and 9). The 2006 and 2005 amounts were restated for discontinued operations (See Note 3).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First [a]	Second [a]	Third [a]	Fourth [a]
2006				
Operating revenues	**$978**	**$936**	**$1,200**	**$972**
Operating income	**189**	**174**	**346**	**178**
Net income	**86**	**76**	**189**	**106**
2005				
Operating revenues	$935	$861	$1,185	$1,010
Operating income	221	140	343	227
Net income	116	67	184	126

[a] Certain amounts have been reclassified to conform to current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. The first quarter of 2005 included $14 million recorded for estimated severance expense for workforce restructuring; the second and fourth quarters of 2005 included reversals of estimated severance expense of $6 million and $5 million, respectively. The second quarter of 2005 included a $29 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A).

PEF

Summarized quarterly financial data was as follows:

(in millions)	First [a]	Second [a]	Third [a]	Fourth [a]
2006				
Operating revenues	**$1,007**	**$1,147**	**$1,399**	**$1,086**
Operating income	**117**	**167**	**237**	**122**
Net income	**53**	**87**	**125**	**63**
2005				
Operating revenues	$848	$908	$1,227	$972
Operating income	89	51	247	112
Net income	44	10	151	55

[a] Certain amounts have been reclassified to conform to current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. The first quarter of 2005 included $14 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative; the second and fourth quarters of 2005 included reversals of estimated severance expense of $5 million and $6 million, respectively. The second quarter of 2005 included a $90 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Company's internal control over financial reporting at December 31, 2006, and the effectiveness of the Company's internal control over financial reporting at December 31, 2006, and have issued our reports thereon dated February 28, 2007 (which reports on the consolidated financial statements express an unqualified opinion and include an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005); such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

PROGRESS ENERGY, INC.
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Other Additions	Deductions [a]	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
DECEMBER 31, 2006					
Uncollectible accounts	**$19**	**$29**	**$ –**	**$(20)**	**$28**
Fossil fuel plants dismantlement reserve	**145**	**1**	**–**	**(1)**	**145**
Nuclear refueling outage reserve	**2**	**14**	**–**	**–**	**16**
DECEMBER 31, 2005					
Uncollectible accounts	$22	$16	$ –	$(19)	$19
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	12	11	–	(21) [b]	2
DECEMBER 31, 2004					
Uncollectible accounts	$28	$14	$(4)	$(16)	$22
Fossil fuel plants dismantlement reserve	143	1	–	–	144
Nuclear refueling outage reserve	2	10	–	–	12

[a] Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.

[b] Represents payments of actual expenditures related to the outages.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) at December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 28, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005); such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of PEC listed in Item 15. This consolidated financial statement schedule is the responsibility of PEC's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expense	Other Additions	Deductions (a)	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
DECEMBER 31, 2006					
Uncollectible accounts	**$4**	**$9**	**$–**	**$(8)**	**$5**
DECEMBER 31, 2005					
Uncollectible accounts	$10	$5	$–	$(11)	$4
DECEMBER 31, 2004					
Uncollectible accounts	$17	$7	$(4)	$(10)	$10

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. Such deductions are reduced by recoveries of amounts previously written off.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the financial statements of Florida Power Corporation d/b/a Progress Energy Florida, Inc., (PEF) at December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 28, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of PEF listed in Item 15. This financial statement schedule is the responsibility of PEF's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning Of Period	Additions Charged to Expense	Other Additions	Deductions (a)	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
DECEMBER 31, 2006					
Uncollectible accounts	**\$6**	**\$14**	**\$–**	**\$(12)**	**\$8**
Fossil fuel plants dismantlement reserve	**145**	**1**	**–**	**(1)**	**145**
Nuclear refueling outage reserve	**2**	**14**	**–**	**–**	**16**
DECEMBER 31, 2005					
Uncollectible accounts	\$2	\$10	\$–	\$(6)	\$6
Fossil fuel plants dismantlement reserve	144	1	–	–	145
Nuclear refueling outage reserve	12	11	–	(21) [b]	2
DECEMBER 31, 2004					
Uncollectible accounts	\$2	\$5	\$–	\$(5)	\$2
Fossil fuel plants dismantlement reserve	143	1	–	–	144
Nuclear refueling outage reserve	2	10	–	–	12

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.

(b) Represents payments of actual expenditures related to the outages.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Progress Energy, Inc.

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with 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, 2006. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2006, Progress Energy maintained effective internal control over financial reporting.

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2006, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, 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, 2006 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying *Management's Report of Internal Controls*, that Progress Energy, Inc., and its subsidiaries (the "Company") maintained effective internal control over financial reporting at December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting at December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006, of the Company and our report dated February 28, 2007, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the adoption of new accounting principles.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina

February 28, 2007

PEC

Pursuant to the Securities Exchange Act of 1934, PEC carried out an evaluation, with the participation of its management, including PEC's Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEC's disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEC's Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by PEC in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to PEC's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in PEC's internal control over financial reporting during the quarter ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PEF

Pursuant to the Securities Exchange Act of 1934, PEF carried out an evaluation, with the participation of its management, including PEF's Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEF's disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEF's Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by PEF in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to PEF's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in PEF's internal control over financial reporting during the quarter ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

a) Information on Progress Energy, Inc.'s directors is set forth in Progress Energy's definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated by reference herein. Information on PEC's directors is set forth in PEC's definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

b) Information on both Progress Energy's and PEC's executive officers is set forth in PART I and incorporated by reference herein.

c) We have adopted a Code of Ethics that applies to all of our employees, including our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller (or persons performing similar functions). Our board of directors has adopted our Code of Ethics as its own standard. Board members, Progress Energy officers and Progress Energy employees certify their compliance with the Code of Ethics on an annual basis. Our Code of Ethics is posted on our Web site at www.progress-energy.com and is available in print to any shareholder upon written request.

We intend to satisfy the disclosure requirement under Item 10 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller by posting such information on our Web site cited above.

d) The board of directors has determined that Carlos A. Saladrigas and Theresa M. Stone are the "Audit Committee Financial Experts," as that term is defined in the rules promulgated by the SEC pursuant to the Sarbanes-Oxley Act of 2002, and have designated them as such. Both Mr. Saladrigas and Ms. Stone are "independent," as that term is defined in the general independence standards of the New York Stock Exchange listing standards.

e) Information regarding our compliance with Section 16(a) of the Securities Exchange Act of 1934 and certain corporate governance matters is set forth in Progress Energy's and PEC's definitive proxy statements for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

f) The following are available on our Web site cited above and in print at no cost:

- Audit and Corporate Performance Committee Charter
- Corporate Governance Committee Charter
- Organization and Compensation Committee Charter
- Corporate Governance Guidelines

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

ITEM 11. EXECUTIVE COMPENSATION

Information on Progress Energy's executive compensation is set forth in Progress Energy's definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated by reference herein. Information on PEC's executive compensation is set forth in PEC's definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by Item 11 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

a) Information regarding any person Progress Energy knows to be the beneficial owner of more than five (5%) percent of any class of its voting securities is set forth in its definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated herein by reference.

Information regarding any person PEC knows to be the beneficial owner of more than five percent of any class of its voting securities is set forth in its definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated herein by reference.

b) Information on security ownership of Progress Energy's and PEC's management is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

c) Information on the equity compensation plans of Progress Energy is set forth under the heading "Equity Compensation Plan Information" in Progress Energy's definitive proxy statement for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by Item 12 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by Item 13 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The Audit and Corporate Performance Committee of Progress Energy's board of directors ("Audit Committee") has actively monitored all services provided by its independent registered public accounting firm, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and nonaudit services provided by Deloitte. Progress Energy has adopted policies and procedures for approving all audit and permissible nonaudit services rendered by Deloitte, and the fees billed for those services. The Controller is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. The Audit Committee specifically preapproved the use of Deloitte for audit, audit-related, tax and nonaudit services, subject to the limitations of our preapproval policy. Audit and audit-related services include assurance and related activities; assurance services associated with internal control over financial reporting; review of reports for regulatory filings, releases containing financial information and financing-related materials; consultations on dispositions and discontinued operations; audits of employee benefit plan; and consultation on accounting issues. The preapproval policy provides that any audit and audit-related services with projected expenditure of over $50,000 and not previously preapproved, will require individual approval by the Audit Committee in advance of Deloitte being engaged to render such services. Once the cumulative total of those projects less than $50,000, plus projected overruns in excess of previously approved amounts, exceeds $500,000 for the year, each subsequent project, regardless of amount, must be approved individually in advance by the Audit Committee.

The preapproval policy requires management to obtain specific preapproval from the Audit Committee for the use of Deloitte for any permissible nonaudit services, which, generally, are limited to tax services, including tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible nonaudit services will not be considered for approval except in limited instances, which may include proposed services that provide significant economic or other benefits. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible nonaudit services provided during a fiscal year that (i) do not aggregate more than five percent of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as nonaudit services at the time of the engagement must be brought to the attention of the Controller for prompt submission to the Audit Committee for approval. These "de minimis" nonaudit services must be approved by the Audit Committee or its designated representative before the completion of the services. The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and New York Stock Exchange standards. The Audit Committee will assess the adequacy of this policy and related procedure as it deems necessary and revise accordingly.

Information regarding principal accountant fees and services is set forth, respectively, in Progress Energy's and PEC's definitive proxy statements for the 2007 Annual Meeting of Shareholders and incorporated by reference herein.

PEF

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to PEF for the fiscal years ended December 31.

	2006	2005
Audit fees	**$906,000**	$1,282,000
Audit-related fees	**44,000**	18,000
Tax fees	**103,000**	179,000
All other fees	**4,000**	–
Total	**$1,057,000**	$1,479,000

Audit fees include fees billed for services rendered in connection with (i) the audits of the annual financial statements of PEF (ii) the audit of management's assessment of internal control over financial reporting; (iii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of PEF, (iv) SEC filings, (v) accounting consultations arising as part of the audits and (vi) comfort letters.

Audit-related fees include fees billed for (i) special procedures and letter reports, (ii) benefit plan audits when fees are paid by PEF rather than directly by the plan; and (iii) accounting consultations for prospective transactions not arising directly from the audits.

Tax fees include fees billed for tax compliance matters and tax planning and advisory services.

All other fees include fees billed for utility accounting training.

The Audit Committee has concluded that the provision of the nonaudit services listed above as "All other fees" is compatible with maintaining Deloitte's independence.

None of the services provided were approved by the Audit Committee pursuant to the "de minimis" waiver provisions described above.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of the report:

1. Financial Statements Filed:

   See Item 8 –Financial Statements and Supplementary Data

2. Financial Statement Schedules Filed:

   See Item 8 –Financial Statements and Supplementary Data

3. Exhibits Filed:

   See EXHIBIT INDEX

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY
(Registrants)

Date: February 26, 2007

By: /s/ Robert B. McGehee
Robert B. McGehee
Chairman and Chief Executive Officer
Progress Energy, Inc.
Chairman
Carolina Power & Light Company

By: /s/ Fred N. Day IV
Fred N. Day IV
President and Chief Executive Officer
Carolina Power & Light Company

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer
Progress Energy, Inc.
Carolina Power & Light Company

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer and Controller
Progress Energy, Inc.
Chief Accounting Officer
Carolina Power & Light Company

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ Robert B. McGehee (Robert B. McGehee)	Chairman	February 26, 2007
/s/ Edwin B. Borden (Edwin B. Borden)	Director	February 26, 2007
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	February 26, 2007

/s/ David L. Burner (David L. Burner)	Director	February 26, 2007
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	February 26, 2007
/s/ Harris E. DeLoach, Jr. (Harris E. DeLoach, Jr.)	Director	February 26, 2007
/s/ W. D. Frederick, Jr. (W. D. Frederick, Jr.)	Director	February 26, 2007
/s/ W. Steven Jones (W. Steven Jones)	Director	February 26, 2007
/s/ E. Marie McKee (E. Marie McKee)	Director	February 26, 2007
/s/ John H. Mullin, III (John H. Mullin, III)	Director	February 26, 2007
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	February 26, 2007
/s/ Theresa M. Stone (Theresa M. Stone)	Director	February 26, 2007
/s/ Alfred C. Tollison, Jr. (Alfred C. Tollison, Jr.)	Director	February 26, 2007
/s/ Jean Giles Wittner (Jean Giles Wittner)	Director	February 26, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

Date: February 26, 2007

FLORIDA POWER CORPORATION
(Registrant)

By: /s/ Jeffrey J. Lyash
Jeffrey J. Lyash
President and Chief Executive Officer

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ Robert B. McGehee (Robert B. McGehee)	Chairman	February 26, 2007
/s/ Jeffrey A. Corbett (Jeffrey A. Corbett)	Director	February 26, 2007
/s/ Fred N. Day IV (Fred N. Day IV)	Director	February 26, 2007
/s/ William D. Johnson (William D. Johnson)	Director	February 26, 2007
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	February 26, 2007
/s/ John R. McArthur (John R. McArthur)	Director	February 26, 2007
/s/ Peter M. Scott III (Peter M. Scott III)	Director	February 26, 2007

EXHIBIT INDEX

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
*3a(1)	Restated Charter of Carolina Power & Light Company, as amended May 10, 1995 (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1995, File No. 1-3382).		X	
*3a(2)	Restated Charter of Carolina Power & Light Company as amended on May 10, 1996 (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-3382).		X	
*3a(3)	Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), as amended and restated on June 15, 2000 (filed as Exhibit No. 3a(1) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15929 and No. 1-3382).	X		
*3a(4)	Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), as amended and restated on December 4, 2000 (filed as Exhibit 3b(1) to Annual Report on Form 10-K for the year ended December 31, 2001, as filed with the SEC on March 28, 2002, File No. 1-15929).	X		
*3a(5)	Amended Articles of Incorporation of Progress Energy, Inc., as amended on May 10, 2006 (filed as Exhibit 3.A to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274.)	X		
*3a(6)	Amended Articles of Incorporation of Florida Power Corporation (filed as Exhibit 3(a) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 1991, as filed with the SEC on March 30, 1992, File No. 1-3274).			X
*3b(1)	By-Laws of Progress Energy, Inc., as amended on May 10, 2006 (filed as Exhibit 3.B to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-15929, 1-3382 and 1-3274).	X		
*3b(2)	By-Laws of Carolina Power & Light Company, as amended on March 17, 2004 (filed as Exhibit No. 3(ii)(b) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, File No. 1-3382 and 1-15929).		X	
*3b(3)	Bylaws of Progress Energy Florida, as amended October 1, 2001 (filed as Exhibit 3.(d) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-8349 and 1-3274).			X
*4a(1)	Description of Preferred Stock and the rights of the		X	

	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).	
*4a(2)	Statement of Classification of Shares dated January 13, 1971, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.95 Series (filed as Exhibit 3(f), File No. 33-25560).	X
*4a(3)	Statement of Classification of Shares dated September 7, 1972, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.72 Series (filed as Exhibit 3(g), File No. 33-25560).	X
*4b(1)	Mortgage and Deed of Trust dated as of May 1, 1940 between Carolina Power & Light Company and The Bank of New York (formerly, Irving Trust Company) and Frederick G. Herbst (Douglas J. MacInnes, Successor), Trustees and the First through Fifth Supplemental Indentures thereto (Exhibit 2(b), File No. 2-64189); the Sixth through Sixty-sixth Supplemental Indentures (Exhibit 2(b)-5, File No. 2-16210; Exhibit 2(b)-6, File No. 2-16210; Exhibit 4(b)-8, File No. 2-19118; Exhibit 4(b)-2, File No. 2-22439; Exhibit 4(b)-2, File No. 2-24624; Exhibit 2(c), File No. 2-27297; Exhibit 2(c), File No. 2-30172; Exhibit 2(c), File No. 2-35694; Exhibit 2(c), File No. 2-37505; Exhibit 2(c), File No. 2-39002; Exhibit 2(c), File No. 2-41738; Exhibit 2(c), File No. 2-43439; Exhibit 2(c), File No. 2-47751; Exhibit 2(c), File No. 2-49347; Exhibit 2(c), File No. 2-53113; Exhibit 2(d), File No. 2-53113; Exhibit 2(c), File No. 2-59511; Exhibit 2(c), File No. 2-61611; Exhibit 2(d), File No. 2-64189; Exhibit 2(c), File No. 2-65514; Exhibits 2(c) and 2(d), File No. 2-66851; Exhibits 4(b)-1, 4(b)-2, and 4(b)-3, File No. 2-81299; Exhibits 4(c)-1 through 4(c)-8, File No. 2-95505; Exhibits 4(b) through 4(h), File No. 33-25560; Exhibits 4(b) and 4(c), File No. 33-33431; Exhibits 4(b) and 4(c), File No. 33-38298; Exhibits 4(h) and 4(i), File No. 33-42869; Exhibits 4(e)-(g), File No. 33-48607; Exhibits 4(e) and 4(f), File No. 33-55060; Exhibits 4(e) and 4(f), File No. 33-60014; Exhibits 4(a) and 4(b) to Post-Effective Amendment No. 1, File No. 33-38349; Exhibit 4(e), File No. 33-50597; Exhibit 4(e) and 4(f), File No. 33-57835; Exhibit to Current Report on Form 8-K dated August 28, 1997, File No. 1-3382; Form of Carolina Power & Light Company First Mortgage Bond, 6.80% Series Due August 15, 2007 filed as Exhibit 4 to Form 10-Q for the period ended September 30, 1998, File No. 1-3382; Exhibit 4(b), File No. 333-69237; and Exhibit 4(c) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382.); and the Sixty-eighth Supplemental Indenture (Exhibit No. 4(b) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382; and the Sixty-ninth Supplemental Indenture	X

	(Exhibit No. 4b(2) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventieth Supplemental Indenture, (Exhibit 4b(3) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventy-first Supplemental Indenture (Exhibit 4b(2) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3382 and 1-15929); and the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated September 12, 2003, File No. 1-3382); and the Seventy-third Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated March 22, 2005, File No. 1-3382); and the Seventy-fourth Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated November 30, 2005, File No. 1-3382).	
*4b(2)	Indenture, dated as of January 1, 1944 (the "Indenture"), between Florida Power Corporation and Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees (filed as Exhibit B-18 to Florida Power's Registration Statement on Form A-2) (No. 2-5293) filed with the SEC on January 24, 1944).	X
*4b(3)	Seventh Supplemental Indenture (filed as Exhibit 4(b) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Eighth Supplemental Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Sixteenth Supplemental Indenture (filed as Exhibit 4(d) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991); and the Twenty-ninth Supplemental Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 2-79832) filed with the SEC on September 17, 1982); and the Thirty-eighth Supplemental Indenture (filed as exhibit 4(f) to Florida Power's Registration Statement on Form S-3 (No. 33-55273) as filed with the SEC on August 29, 1994); and the Thirty-ninth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on July 23, 2001); and the Fortieth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 18, 2003); and the Forty-first Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 21, 2003); and the Forty-second Supplemental Indenture (filed as Exhibit 4 to Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 filed with the SEC on September 11, 2003); and the Forty-third Supplemental Indenture (filed as Exhibit 4 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).	X

*4b(4)	Indenture, dated as of December 7, 2005, between Progress Energy Florida, Inc. and J.P. Morgan Trust Company, National Association, as Trustee with respect to Senior Notes, (filed as Exhibit 4(a) to Current Report on Form 8-K dated December 13, 2005, File No. 1-3274).			X
*4b(5)	Indenture, dated as of March 1, 1995, between Carolina Power & Light Company and Bankers Trust Company, as Trustee, with respect to Unsecured Subordinated Debt Securities (filed as Exhibit No. 4(c) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X	
*4b(6)	Indenture, dated as of February 15, 2001, between Progress Energy, Inc. and Bank One Trust Company, N.A., as Trustee, with respect to Senior Notes (filed as Exhibit 4(a) to Form 8-K dated February 27, 2001, File No. 1-15929).	X		
*4c	Resolutions adopted by the Executive Committee of the Board of Directors at a meeting held on April 13, 1995, establishing the terms of the 8.55% Quarterly Income Capital Securities (Series A Subordinated Deferrable Interest Debentures) (filed as Exhibit 4(b) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X	
*4d	Indenture (for Senior Notes), dated as of March 1, 1999 between Carolina Power & Light Company and The Bank of New York, as Trustee, (filed as Exhibit No. 4(a) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382), and the First and Second Supplemental Senior Note Indentures thereto (Exhibit No. 4(b) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382); Exhibit No. 4(a) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382).		X	
*4e	Indenture (For Debt Securities), dated as of October 28, 1999 between Carolina Power & Light Company and The Chase Manhattan Bank, as Trustee (filed as Exhibit 4(a) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382), (Exhibit 4(b) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382).		X	
*4f	Contingent Value Obligation Agreement, dated as of November 30, 2000, between CP&L Energy, Inc. and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to Current Report on Form 8-K dated December 12, 2000, File No. 1-3382).	X		
*10a(1)	Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letter dated February 18, 1982, and amendment dated February 24, 1982 (filed as Exhibit 10(a), File No. 33-25560).		X	

*10a(2)	Operating and Fuel Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10(b), File No. 33-25560).		X	
*10a(3)	Power Coordination Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982 (filed as Exhibit 10(c), File No. 33-25560).		X	
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).		X	
*10b(1)	Progress Energy, Inc. $1,130,000,000 5-Year Revolving Credit Agreement dated as of May 3, 2006 (filed as Exhibit 10(c) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).	X		
*10b(2)	PEF 5-Year $450,000,000 Credit Agreement, dated as of March 28, 2005 (filed as Exhibit 10(ii) to Current Report on Form 8-K filed April 1, 2005, File No. 1-3274).			X
*10b(3)	Amendment dated as of May 3, 2006, to the 5-Year $450,000,000 Credit Agreement among PEF and certain lenders, dated March 28, 2005 (filed as Exhibit 10(e) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).			X
*10b(4)	PEC 5-¼-Year $450,000,000 Credit Agreement dated as of March 28, 2005 (filed as Exhibit 10(i) to Current Report on Form 8-K filed April 1, 2005, File No. 1-3382).		X	
*10b(5)	Amendment dated as of May 3, 2006, to the 5-¼-Year $450,000,000 Credit Agreement among PEC and certain lenders, dated March 28, 2005 (filed as Exhibit 10(d) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-15929, 1-3274 and 1-3382).		X	
-+*10c(1)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).		X	
+*10c(2)	Resolutions of Board of Directors dated July 9, 1997, amending the Deferred Compensation Plan for Key Management Employees of Carolina Power & Light Company.		X	

+*10c(3)	Progress Energy, Inc. Form of Stock Option Agreement (filed as Exhibit 4.4 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X	X
+*10c(4)	Progress Energy, Inc. Form of Stock Option Award (filed as Exhibit 4.5 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X	X
+10c(5)	2002 Progress Energy, Inc. Equity Incentive Plan, Amended and Restated effective January 1, 2007.	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.	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).	X	X	X
+10c (8)	Amended and Restated Management Incentive Compensation Plan of Progress Energy, Inc., effective January 1, 2007.	X	X	X
+10c(9)	Amended and Restated Management Deferred Compensation Plan of Progress Energy, Inc., effective as of January 1, 2007.	X	X	X
+10c(10)	Amended and Restated Management Change-in-Control Plan of Progress Energy, Inc., effective as of January 1, 2007.	X	X	X
+10c(11)	Amended and Restated Non-Employee Director Deferred Compensation Plan of Progress Energy, Inc., effective January 1, 2007.	X	X	X
+10c(12)	Amended and Restated Restoration Retirement Plan of Progress Energy, Inc., effective January 1, 2007.	X	X	X
+10c(13)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., effective January 1, 2007.	X	X	X
+10c(14)	Amended and Restated Non-Employee Director Stock Unit Plan of Progress Energy, Inc., effective January 1, 2007.	X	X	X
+*10c(15)	Form of Progress Energy, Inc. Restricted Stock Agreement pursuant to the 2002 Progress Energy Inc. Equity Incentive Plan, as amended July 2002 (filed as Exhibit 10c(18) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(16)	Employment Agreement dated August 1, 2000 between CP&L Service Company LLC and Robert McGehee (filed as Exhibit 10(iv) to Quarterly Report on Form 10-Q for	X		

	the period ended September 30, 2000, File No. 1-15929 and No. 1-3382).			
+*10c(17)	Form of Employment Agreement dated August 1, 2000 between CP&L Service Company LLC and Peter M. Scott III (filed as Exhibit 10(v) to Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X	X
+*10c(18)	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(19)	Form of Employment Agreement dated August 1, 2000 between Carolina Power & Light Company and Fred Day IV and C.S. "Scotty" Hinnant (filed as Exhibit 10(vi) to Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X	
+*10c(20)	Form of Employment Agreement between Progress Energy Service Company and John R. McArthur, effective January 2003 (filed as Exhibit 10c(27) to Annual Report on Form 10-K for the year ended December 31, 2002, as filed with the SEC on March 21, 2003, File No. 1-3382 and 1-15929).	X	X	X
+*10c(21)	Employment Agreement dated January 1, 2005 between Progress Energy Carolinas, Inc. and William D. Johnson (filed as Exhibit 10c(29) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+10c(22)	Selected Executives Supplemental Deferred Compensation Program Agreement, dated August, 1996, between CP&L and C. S. Hinnant.		X	
+10c(23)	Form of Executive Permanent Life Insurance Agreement.			
*10d(1)	Agreement dated November 18, 2004 between Winchester Production Company, Ltd., TGG Pipeline Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 10d(1) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X		X
*10d(2)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company ("SNG"), Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between SNG and PEF, dated December 2, 2004; b) Gas Sale and Purchase Contract between BG and PEF, dated December 1, 2004;	X		X

	c) Interim Firm Transportation Service Agreement by and between FGT and PEF, dated December 2, 2004; d) Letter Agreement between FGT and PEF, dated December 2, 2004 and Firm Transportation Service Agreement by and between FGT and PEF to be entered into upon satisfaction of certain conditions precedent; e) Discount Agreement between FGT and PEF, dated December 2, 2004; f) Amendment to Gas Sale and Purchase Contract between BG and PEF, dated January 28, 2005; and g) Letter Agreement between FGT and PEF, dated January 31, 2005, (filed as Exhibit 10.1 to Current Report on Form 8-K/A filed March 15, 2005). (Confidential treatment has been requested for portions of this exhibit. These portions have been omitted from the above-referenced Current Report and submitted separately to the SEC.)			
12(a)	Computation of Ratio of Earnings to Fixed Charges.	X		
12(b)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.		X	
12(c)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.			X
21	Subsidiaries of Progress Energy, Inc.	X		
23(a)	Consent of Deloitte & Touche LLP.	X		
23(b)	Consent of Deloitte & Touche LLP.		X	
31(a)	302 Certification of Chief Executive Officer	X		
31(b)	302 Certification of Chief Financial Officer	X		
31(c)	302 Certification of Chief Executive Officer		X	
31(d)	302 Certification of Chief Financial Officer		X	
31(e)	302 Certification of Chief Executive Officer			X
31(f)	302 Certification of Chief Financial Officer			X
32(a)	906 Certification of Chief Executive Officer	X		
32(b)	906 Certification of Chief Financial Officer	X		
32(c)	906 Certification of Chief Executive Officer		X	

32(d)	906 Certification of Chief Financial Officer	X	
32(e)	906 Certification of Chief Executive Officer		X
32(f)	906 Certification of Chief Financial Officer		X

*Incorporated herein by reference as indicated.
+Management contract or compensatory plan or arrangement required to be filed as an exhibit to this form pursuant to Item 15 (b) of this report.
-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.

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31

(dollars in millions)	**2006**	2005	2004	2003	2002
Earnings, as defined:					
Income from continuing operations before minority interest	**$523**	$692	$654	$771	$546
Fixed charges, as below	**651**	606	591	590	632
Preferred dividend requirements	**(7)**	(7)	(7)	(7)	(7)
Minority interest	**(9)**	29	19	–	–
Income taxes, as below	**199**	(42)	62	(138)	(152)
Total earnings, as defined	**$1,357**	$1,278	$1,319	$1,216	$1,019
Fixed Charges, as defined:					
Interest on long-term debt	**$619**	$566	$529	$543	$541
Other interest	**13**	21	43	27	71
Imputed interest factor in rentals – charged principally to operating expenses	**12**	12	12	13	13
Preferred dividend requirements of subsidiaries	**7**	7	7	7	7
Total fixed charges, as defined	**$651**	$606	$591	$590	$632
Income Taxes:					
Income tax expense (benefit)	**$204**	$(37)	$67	$(130)	$(144)
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(8)	(8)
Total income taxes	**$199**	$(42)	$62	$(138)	$(152)
Ratio of Earnings to Fixed Charges	**2.08**	2.11	2.23	2.06	1.61

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)	**2006**	2005	2004	2003	2002
Earnings, as defined:					
Income before cumulative effect of changes in accounting principles	**\$457**	\$493	\$461	\$504	\$431
Fixed charges, as below	**225**	205	201	206	224
Income taxes, as below	**260**	234	234	233	199
Total earnings, as defined	**\$942**	\$932	\$896	\$943	\$854
Fixed Charges, as defined:					
Interest on long-term debt	**\$218**	\$191	\$183	\$188	\$205
Other interest	**(1)**	6	11	11	12
Imputed interest factor in rentals – charged principally to operating expenses	**8**	8	7	7	7
Total fixed charges, as defined	**225**	205	201	206	224
Preferred dividends, as defined	**5**	4	5	4	4
Total fixed charges and preferred dividends combined	**\$230**	\$209	\$206	\$210	\$228
Income Taxes:					
Income tax expense	**\$265**	\$239	\$239	\$241	\$207
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(5)	(8)	(8)
Total income taxes	**\$260**	\$234	\$234	\$233	\$199
Ratio of Earnings to Fixed Charges	**4.19**	4.55	4.45	4.59	3.81
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.10**	4.46	4.36	4.50	3.74

Exhibit No. 12 (c)

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2006**	2005	2004	2003	2002
Earnings, as defined:					
Net income	**$328**	$260	$335	$297	$325
Fixed charges, as below	**159**	138	122	103	114
Income taxes	**193**	121	174	147	163
Total earnings, as defined	**$680**	$519	$631	$547	$602
Fixed Charges, as defined:					
Interest on long-term debt	**$145**	$116	$107	$103	$99
Other interest	**10**	18	10	(6)	10
Imputed interest factor in rentals – charged principally to operating expenses	**4**	4	5	6	5
Total fixed charges, as defined	**159**	138	122	103	114
Preferred dividends, as defined	**2**	2	2	2	3
Total fixed charges and preferred dividends combined	**$161**	$140	$124	$105	$117
Ratio of Earnings to Fixed Charges	**4.28**	3.76	5.17	5.31	5.27
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**4.22**	3.71	5.08	5.21	5.13

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, 2006. 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
CaroFinancial, Inc.	North Carolina
Florida Progress Corporation	Florida
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.	Florida
Progress Capital Holdings, Inc.	Florida
Progress Telecommunications Corporation	Florida
Progress Fuels Corporation	Florida
EFC Synfuel LLC	Delaware
Ceredo Synfuel LLC	Delaware
Solid Energy LLC	Delaware
Kanawha River Terminals, Inc.	Florida
Black Hawk Synfuel LLC	Delaware
PV Holdings, Inc.	North Carolina
Progress Ventures, Inc. d/b/a Progress Energy Ventures, Inc.	North Carolina
Progress Genco Ventures, LLC	North Carolina
PV Synfuels, LLC	North Carolina
Solid Fuel, LLC	Delaware
Sandy River Synfuel, LLC	Delaware
Progress Energy Service Company, LLC	North Carolina

Exhibit No. 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 33–33520 on Form S–8, Post–Effective Amendment 1 to Registration Statement No. 33–38349 on Form S–3, Registration Statement No. 333–81278 on Form S–3, Registration Statement No. 333–81278–01 on Form S–3, Registration Statement No. 333–81278–02 on Form S–3, Registration Statement No. 333–81278–03 on Form S–3, Post–Effective Amendment 1 to Registration Statement No. 333–69738 on Form S–3, Registration Statement No. 333–70332 on Form S–8, Registration Statement No. 333–87274 on Form S–3, Post–Effective Amendment 1 to Registration Statement No. 333–47910 on Form S–3, Registration Statement No. 333–52328 on Form S–8, Post–Effective Amendment 1 to Registration Statement No. 333–89685 on Form S–8, Registration Statement No. 333–48164 on Form S–8, Registration Statement No. 333-114237 on Form S-3, Registration Statement No. 333-104951 on Form S-8 and Registration Statement No. 333-104952 on Form S-8 of our reports dated February 28, 2007 relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc. (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10–K of Progress Energy, Inc. for the year ended December 31, 2006.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

Exhibit No. 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333−126966 on Form S−3 of our reports dated February 28, 2007, relating to the consolidated financial statements and consolidated financial statement schedule of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005), appearing in this Annual Report on Form 10−K of PEC for the year ended December 31, 2006.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

Exhibit No. 23(c)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-126967 on Form S-3 of our reports dated February 28, 2007, relating to the financial statements and financial statement schedule of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) (which report on the financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2006 and 2005) appearing in this Annual Report on Form 10–K of PEF for the year ended December 31, 2006.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007