CAROLINA POWER & LIGHT CO
Form 10-Q
August 06, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2010

OR

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

For the transition period from to .

Commission File Number	Exact name of registrants as specified in their charters, states of incorporation, addresses of principal executive offices, and telephone numbers	I.R.S. Employer Identification Number
1-15929	Progress Energy, Inc. 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-2155481
1-3382	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-0165465
1-3274	Florida Power Corporation d/b/a Progress Energy Florida, Inc. 299 First Avenue North St. Petersburg, Florida 33701 Telephone: (727) 820-5151 State of Incorporation: Florida	59-0247770

NONE

(Former name, former address and former fiscal year, if changed since last report)

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

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

Indicate by check mark whether each registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Progress Energy	Yes	x	No	o
PEC	Yes	o	No	o
PEF	Yes	o	No	o

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

Progress Energy	Large accelerated filer	x	Accelerated filer	o
	Non-accelerated filer	o	Smaller reporting company	o
PEC	Large accelerated filer	o	Accelerated filer	o
	Non-accelerated filer	x	Smaller reporting company	o
PEF	Large accelerated filer	o	Accelerated filer	o
	Non-accelerated filer	x	Smaller reporting company	o

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

Progress Energy	Yes	o	No	x
PEC	Yes	o	No	x
PEF	Yes	o	No	x

At August 2, 2010, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	292,581,000
PEC	Common Stock (Without Par Value)	159,608,055 (all of which were held directly by Progress Energy, Inc.)
PEF	Common Stock (Without Par Value)	100 (all of which were held indirectly by Progress Energy, Inc.)

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

PEF meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format.

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GLOSSARY OF TERMS

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

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

TERM	DEFINITION
2009 Form 10-K	Progress Registrants' annual report on Form 10-K for the fiscal year ended December 31, 2009
401(k)	Progress Energy 401(k) Savings & Stock Ownership Plan
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASLB	Atomic Safety and Licensing Board
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Base Revenues	Non-GAAP measure defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCRC	Capacity Cost-Recovery Clause
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Ceredo	Ceredo Synfuel LLC
CIGFUR	Carolina Industrial Group for Fair Utility Rates II
Clean Smokestacks Act	North Carolina Clean Smokestacks Act
the Code	Internal Revenue Code
CO2	Carbon dioxide
COL	Combined license
Corporate and Other	Corporate and Other segment primarily includes the Parent, Progress Energy Service Company and miscellaneous other nonregulated businesses
CR1 and CR2	PEF's Crystal River Units No. 1 and No. 2 coal-fired steam turbines
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's Crystal River Units No. 4 and No. 5 coal-fired steam turbines
CUCA	Carolina Utility Customer Association

CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DSM	Demand-side management
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three were wholly owned
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

EE	Energy efficiency
EIP	Equity Incentive Plan
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement and construction
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
Fitch	Fitch Ratings
the Florida Global Case	U.S. Global, LLC v. Progress Energy, Inc. et al
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Global	U.S. Global, LLC
GridSouth	GridSouth Transco, LLC
GWh	Gigawatt-hours
Harris	PEC's Shearon Harris Nuclear Plant
IPP	Progress Energy Investor Plus Plan
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Levy	PEF's proposed nuclear plant in Levy County, Fla.
LIBOR	London Inter Bank Offered Rate
MACT	Maximum achievable control technology
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in PART I, Item 2 of this Form 10-Q
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured gas plant
MW	Megawatts
MWh	Megawatt-hours
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCUC	North Carolina Utilities Commission
NDT	Nuclear decommissioning trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
North Carolina Global Case	Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC
the Notes Guarantee	

	Florida Progress' full and unconditional guarantee of the Subordinated Notes
NOx	Nitrogen oxides
NRC	United States Nuclear Regulatory Commission
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
Ongoing Earnings	Non-GAAP financial measure defined as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges
OPC	Florida's Office of Public Counsel

OPEB	Postretirement benefits other than pensions
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
PEF	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
PESC	Progress Energy Service Company, LLC
Power Agency	North Carolina Eastern Municipal Power Agency
PPACA	Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act
Preferred Securities	7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A issued by the Trust
Preferred Securities Guarantee	Florida Progress' guarantee of all distributions related to the Preferred Securities
Progress Affiliates	Five affiliated coal-based solid synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The reporting registrants within the Progress Energy consolidated group. Collectively, Progress Energy, Inc., PEC and PEF
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PUHCA 2005	Public Utility Holding Company Act of 2005
PVI	Progress Energy Ventures, Inc., formerly referred to as Progress Ventures, Inc.
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REPS	Renewable energy portfolio standard
RDS	Retiree Drug Subsidy related to benefits under Medicare Part D
Robinson	PEC's Robinson Nuclear Plant
ROE	Return on equity
RSU	Restricted stock unit
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
Section 29	Section 29 of the Code
Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 316(b)	Section 316(b) of the Clean Water Act
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART I, Item I of this Form 10-Q
SERC	SERC Reliability Corporation
S&P	Standard & Poor's Rating Services
SNG	Southern Natural Gas Company
SO2	Sulfur dioxide
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
Terminals	Coal terminals and docks in West Virginia and Kentucky, which were sold on March 7, 2008

the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
VIE	Variable interest entity
Ward	Ward Transformer site located in Raleigh, N.C.
Ward OU1	Operable unit for stream segments downstream from the Ward site
Ward OU2	Operable unit for further investigation at the Ward facility and certain adjacent areas

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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

In addition, examples of forward-looking statements discussed in this Form 10-Q include, but are not limited to, statements made in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) including, but not limited to, statements under the sub-heading “Results of Operations” about trends and uncertainties; “Liquidity and Capital Resources” about operating cash flows, future liquidity requirements and estimated capital expenditures and “Other Matters” about goodwill, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction, the effects of new environmental regulations, and our synthetic fuel tax credits.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and energy policy; our ability to recover eligible costs and earn an adequate return on investment through the regulatory process; the ability to successfully operate electric generating facilities and deliver electricity to customers; the impact on our facilities and businesses from a terrorist attack; the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, safety, regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and regulations; risks associated with climate change; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; the Progress Registrants’ ability to control costs, including operations and maintenance expense (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to Progress Energy, Inc. holding company (the Parent); current economic conditions; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; the impact that increases in leverage or reductions in cash flow may have on each of the Progress Registrants; the Progress Registrants’ ability to maintain their current credit ratings and the impacts in the event their credit ratings are downgraded; the investment performance of our nuclear decommissioning trust (NDT) funds; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; the impact of potential goodwill impairments; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); and the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in the Progress Registrants’ filings with the SEC. Many, but not all, of the factors that may impact actual results are discussed in the Risk Factors section in the Progress Registrants’ annual report on Form 10-K for the fiscal year ended December 31, 2009 (2009 Form 10-K), which was filed with the SEC on February 26, 2010, and is updated for material changes, if any, in this Form 10-Q and in our other SEC filings. Before purchasing securities of the Progress Registrants, you should carefully consider the risks and other information in the documents the Progress Registrants file with the SEC from time to time. Each of the described risks could result in a decrease in the value of the securities of the Progress Registrants and your investment therein.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PROGRESS ENERGY, INC.
UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
June 30, 2010

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of INCOME

	Three months ended June 30,		Six months ended June 30,	
(in millions except per share data)	2010	2009	2010	2009
Operating revenues	$ 2,372	$ 2,312	$ 4,907	$ 4,754
Operating expenses				
Fuel used in electric generation	743	826	1,639	1,780
Purchased power	315	257	578	474
Operation and maintenance	505	484	985	937
Depreciation, amortization and accretion	233	226	479	506
Taxes other than on income	133	130	287	273
Other	3	10	5	12
Total operating expenses	1,932	1,933	3,973	3,982
Operating income	440	379	934	772
Other income				
Interest income	1	2	3	6
Allowance for equity funds used during construction	25	36	46	75
Other, net	5	13	-	12
Total other income, net	31	51	49	93
Interest charges				
Interest charges	199	181	390	360
Allowance for borrowed funds used during construction	(7)	(12)	(16)	(24)
Total interest charges, net	192	169	374	336
Income from continuing operations before income tax	279	261	609	529
Income tax expense	98	86	237	171
Income from continuing operations before cumulative effect of change in accounting principle	181	175	372	358
Discontinued operations, net of tax	(1)	(1)	-	(1)
Cumulative effect of change in accounting principle, net of tax	-	-	(2)	-
Net income	180	174	370	357
Net income attributable to noncontrolling interests, net of tax	-	-	-	(1)
Net income attributable to controlling interests	$ 180	$ 174	$ 370	$ 356
Average common shares outstanding – basic	290	280	287	278

Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	$ 0.62	$ 0.62	$ 1.29	$ 1.28
Discontinued operations attributable to controlling interests, net of tax	-	-	-	-
Net income attributable to controlling interests	$ 0.62	$ 0.62	$ 1.29	$ 1.28
Dividends declared per common share	$ 0.620	$ 0.620	$ 1.240	$ 1.240
Amounts attributable to controlling interests				
Income from continuing operations, net of tax	$ 181	$ 175	$ 370	$ 357
Discontinued operations, net of tax	(1)	(1)	-	(1)
Net income attributable to controlling interests	$ 180	$ 174	$ 370	$ 356

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

PROGRESS ENERGY, INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	June 30, 2010	December 31, 2009
ASSETS		
Utility plant		
Utility plant in service	$ 29,728	$ 28,918
Accumulated depreciation	(11,777)	(11,576)
Utility plant in service, net	17,951	17,342
Held for future use	48	47
Construction work in progress	1,914	1,790
Nuclear fuel, net of amortization	599	554
Total utility plant, net	20,512	19,733
Current assets		
Cash and cash equivalents	690	725
Receivables, net	999	800
Inventory	1,237	1,325
Regulatory assets	324	142
Derivative collateral posted	194	146
Income taxes receivable	21	145
Prepayments and other current assets	195	248
Total current assets	3,660	3,531
Deferred debits and other assets		
Regulatory assets	2,211	2,179
Nuclear decommissioning trust funds	1,341	1,367
Miscellaneous other property and investments	437	438
Goodwill	3,655	3,655
Other assets and deferred debits	321	333
Total deferred debits and other assets	7,965	7,972
Total assets	$ 32,137	$ 31,236
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 293 million and 281 million shares issued and outstanding, respectively	$ 7,304	$ 6,873
Unearned ESOP shares (- and 1 million shares, respectively)	-	(12)
Accumulated other comprehensive loss	(131)	(87)
Retained earnings	2,684	2,675
Total common stock equity	9,857	9,449
Noncontrolling interests	2	6
Total equity	9,859	9,455
Preferred stock of subsidiaries	93	93
Long-term debt, affiliate	272	272
Long-term debt, net	11,664	11,779
Total capitalization	21,888	21,599
Current liabilities		
Current portion of long-term debt	705	406

Short-term debt		-		140
Accounts payable		954		835
Interest accrued		209		206
Dividends declared		182		175
Customer deposits		316		300
Derivative liabilities		250		190
Accrued compensation and other benefits		100		167
Other current liabilities		387		239
Total current liabilities		3,103		2,658
Deferred credits and other liabilities				
Noncurrent income tax liabilities		1,288		1,196
Accumulated deferred investment tax credits		113		117
Regulatory liabilities		2,479		2,510
Asset retirement obligations		1,200		1,170
Accrued pension and other benefits		1,330		1,339
Derivative liabilities		324		240
Other liabilities and deferred credits		412		407
Total deferred credits and other liabilities		7,146		6,979
Commitments and contingencies (Notes 12 and 13)				
Total capitalization and liabilities	$	32,137	$	31,236

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

PROGRESS ENERGY, INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of CASH FLOWS
(in millions)

Six months ended June 30	2010	2009
Operating activities		
Net income	$ 370	$ 357
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, amortization and accretion	555	576
Deferred income taxes and investment tax credits, net	117	13
Deferred fuel (credit) cost	(137)	129
Allowance for equity funds used during construction	(46)	(75)
Other adjustments to net income	136	118
Cash (used) provided by changes in operating assets and liabilities		
Receivables	(126)	(36)
Inventory	87	(118)
Derivative collateral posted	(40)	47
Other assets	(13)	41
Income taxes, net	152	110
Accounts payable	110	(30)
Other liabilities	(6)	(37)
Net cash provided by operating activities	1,159	1,095
Investing activities		
Gross property additions	(1,116)	(1,172)
Nuclear fuel additions	(119)	(60)
Purchases of available-for-sale securities and other investments	(3,815)	(982)
Proceeds from available-for-sale securities and other investments	3,792	960
Other investing activities	14	(3)
Net cash used by investing activities	(1,244)	(1,257)
Financing activities		
Issuance of common stock, net	405	545
Dividends paid on common stock	(354)	(347)
Payments of short-term debt with original maturities greater than 90 days	-	(129)
Net decrease in short-term debt	(140)	(521)
Proceeds from issuance of long-term debt, net	591	1,337
Retirement of long-term debt	(400)	(400)
Other financing activities	(52)	(51)
Net cash provided by financing activities	50	434
Net (decrease) increase in cash and cash equivalents	(35)	272
Cash and cash equivalents at beginning of period	725	180
Cash and cash equivalents at end of period	$ 690	$ 452
Supplemental disclosures		
Significant noncash transactions		
Accrued property additions	$ 274	$ 301

See Notes to Progress Energy, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
June 30, 2010

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of INCOME

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Operating revenues	$1,117	$1,076	$2,380	$2,254
Operating expenses				
Fuel used in electric generation	375	383	858	825
Purchased power	76	57	126	114
Operation and maintenance	300	283	585	542
Depreciation, amortization and accretion	120	118	238	235
Taxes other than on income	51	51	111	105
Other	(1)	2	-	2
Total operating expenses	921	894	1,918	1,823
Operating income	196	182	462	431
Other income (expense)				
Interest income	1	1	2	3
Allowance for equity funds used during construction	15	7	28	16
Other, net	4	4	(3)	(3)
Total other income, net	20	12	27	16
Interest charges				
Interest charges	53	52	103	109
Allowance for borrowed funds used during construction	(5)	(3)	(9)	(6)
Total interest charges, net	48	49	94	103
Income before income tax	168	145	395	344
Income tax expense	57	51	146	122
Income before cumulative effect of change in accounting principle	111	94	249	222
Cumulative effect of change in accounting principle, net of tax	-	-	(2)	-
Net income	111	94	247	222
Net loss attributable to noncontrolling interests, net of tax	1	1	3	1
Net income attributable to controlling interests	112	95	250	223
Preferred stock dividend requirement	-	-	(1)	(1)
Net income available to parent	$112	$95	$249	$222

See Notes to Progress Energy Carolinas, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	June 30, 2010	December 31, 2009
ASSETS		
Utility plant		
Utility plant in service	$16,553	$16,297
Accumulated depreciation	(7,631)	(7,520)
Utility plant in service, net	8,922	8,777
Held for future use	12	11
Construction work in progress	1,060	702
Nuclear fuel, net of amortization	430	396
Total utility plant, net	10,424	9,886
Current assets		
Cash and cash equivalents	206	35
Receivables, net	508	442
Receivables from affiliated companies	15	33
Notes receivable from affiliated companies	2	204
Inventory	591	677
Deferred fuel cost	101	88
Income taxes receivable	26	38
Prepayments and other current assets	61	61
Total current assets	1,510	1,578
Deferred debits and other assets		
Regulatory assets	894	873
Nuclear decommissioning trust funds	859	871
Miscellaneous other property and investments	187	199
Other assets and deferred debits	92	95
Total deferred debits and other assets	2,032	2,038
Total assets	$13,966	$13,502
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 200 million shares authorized, 160 million shares issued and outstanding	$2,125	$2,108
Unearned ESOP shares	-	(12)
Accumulated other comprehensive loss	(41)	(27)
Retained earnings	2,785	2,588
Total common stock equity	4,869	4,657
Noncontrolling interests	-	3
Total equity	4,869	4,660
Preferred stock	59	59
Long-term debt, net	3,688	3,703
Total capitalization	8,616	8,422
Current liabilities		
Current portion of long-term debt	6	6
Accounts payable	426	355
Payables to affiliated companies	87	72
Interest accrued	72	70
Customer deposits	101	95

Derivative liabilities	48	29
Accrued compensation and other benefits	53	86
Other current liabilities	122	50
Total current liabilities	915	763
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,327	1,258
Accumulated deferred investment tax credits	107	110
Regulatory liabilities	1,307	1,293
Asset retirement obligations	822	801
Accrued pension and other benefits	703	708
Other liabilities and deferred credits	169	147
Total deferred credits and other liabilities	4,435	4,317
Commitments and contingencies (Notes 12 and 13)		
Total capitalization and liabilities	$13,966	$13,502

See Notes to Progress Energy Carolinas, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS of CASH FLOWS
(in millions)

Six months ended June 30	2010	2009
Operating activities		
Net income	$247	$222
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, amortization and accretion	294	286
Deferred income taxes and investment tax credits, net	55	10
Deferred fuel cost	21	92
Allowance for equity funds used during construction	(28)	(16)
Other adjustments to net income	47	52
Cash (used) provided by changes in operating assets and liabilities		
Receivables	(39)	42
Receivables from affiliated companies	18	13
Inventory	85	(60)
Other assets	(18)	32
Income taxes, net	12	63
Accounts payable	20	(43)
Payables to affiliated companies	15	(24)
Other liabilities	(12)	(23)
Net cash provided by operating activities	717	646
Investing activities		
Gross property additions	(580)	(402)
Nuclear fuel additions	(106)	(42)
Purchases of available-for-sale securities and other investments	(252)	(517)
Proceeds from available-for-sale securities and other investments	227	492
Changes in advances to affiliated companies	202	(75)
Net cash used by investing activities	(509)	(544)
Financing activities		
Dividends paid on preferred stock	(1)	(1)
Dividends paid to parent	(50)	(200)
Net decrease in short-term debt	-	(110)
Proceeds from issuance of long-term debt, net	-	595
Retirement of long-term debt	-	(400)
Contributions from parent	14	15
Other financing activities	-	(1)
Net cash used by financing activities	(37)	(102)
Net increase in cash and cash equivalents	171	-
Cash and cash equivalents at beginning of period	35	18
Cash and cash equivalents at end of period	$206	$18
Supplemental disclosures		
Significant noncash transactions		
Accrued property additions	$158	$128

See Notes to Progress Energy Carolinas, Inc. Unaudited Condensed Consolidated Interim Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
UNAUDITED CONDENSED INTERIM FINANCIAL STATEMENTS
June 30, 2010

UNAUDITED CONDENSED STATEMENTS of INCOME

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Operating revenues	$1,252	$1,234	$2,522	$2,496
Operating expenses				
Fuel used in electric generation	368	443	781	955
Purchased power	239	200	452	360
Operation and maintenance	208	204	413	406
Depreciation, amortization and accretion	110	105	234	265
Taxes other than on income	83	80	176	168
Other	-	7	-	7
Total operating expenses	1,008	1,039	2,056	2,161
Operating income	244	195	466	335
Other income				
Interest income	1	-	1	1
Allowance for equity funds used during construction	10	29	18	59
Other, net	1	7	3	7
Total other income, net	12	36	22	67
Interest charges				
Interest charges	70	64	134	131
Allowance for borrowed funds used during construction	(2)	(9)	(7)	(18)
Total interest charges, net	68	55	127	113
Income before income tax	188	176	361	289
Income tax expense	69	57	140	81
Net income	119	119	221	208
Preferred stock dividend requirement	-	-	(1)	(1)
Net income available to parent	$119	$119	$220	$207

See Notes to Progress Energy Florida, Inc. Unaudited Condensed Interim Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
UNAUDITED CONDENSED BALANCE SHEETS

(in millions)	June 30, 2010	December 31, 2009
ASSETS		
Utility plant		
Utility plant in service	$12,993	$12,438
Accumulated depreciation	(4,075)	(3,987)
Utility plant in service, net	8,918	8,451
Held for future use	36	36
Construction work in progress	854	1,088
Nuclear fuel, net of amortization	169	158
Total utility plant, net	9,977	9,733
Current assets		
Cash and cash equivalents	113	17
Receivables, net	488	356
Receivables from affiliated companies	6	8
Inventory	647	648
Regulatory assets	223	54
Derivative collateral posted	174	139
Deferred tax assets	78	115
Prepayments and other current assets	18	80
Total current assets	1,747	1,417
Deferred debits and other assets		
Regulatory assets	1,317	1,307
Nuclear decommissioning trust funds	482	496
Miscellaneous other property and investments	43	42
Other assets and deferred debits	127	105
Total deferred debits and other assets	1,969	1,950
Total assets	$13,693	$13,100
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	$1,747	$1,744
Accumulated other comprehensive (loss) income	(7)	3
Retained earnings	2,912	2,743
Total common stock equity	4,652	4,490
Preferred stock	34	34
Long-term debt, net	4,481	3,883
Total capitalization	9,167	8,407
Current liabilities		
Current portion of long-term debt	-	300
Notes payable to affiliated companies	7	221
Accounts payable	509	451
Payables to affiliated companies	56	62
Interest accrued	76	72
Customer deposits	215	205
Derivative liabilities	179	161
Accrued compensation and other benefits	29	53

Other current liabilities	247	89
Total current liabilities	1,318	1,614
Deferred credits and other liabilities		
Noncurrent income tax liabilities	877	767
Regulatory liabilities	1,060	1,103
Asset retirement obligations	378	369
Accrued pension and other benefits	389	395
Capital lease obligations	204	208
Derivative liabilities	223	174
Other liabilities and deferred credits	77	63
Total deferred credits and other liabilities	3,208	3,079
Commitments and contingencies (Notes 12 and 13)		
Total capitalization and liabilities	$13,693	$13,100

See Notes to Progress Energy Florida, Inc. Unaudited Condensed Interim Financial Statements.

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FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
UNAUDITED CONDENSED STATEMENTS of CASH FLOWS
(in millions)

Six months ended June 30	2010	2009
Operating activities		
Net income	$221	$208
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, amortization and accretion	244	280
Deferred income taxes and investment tax credits, net	138	(41)
Deferred fuel (credit) cost	(158)	37
Allowance for equity funds used during construction	(18)	(59)
Other adjustments to net income	62	47
Cash (used) provided by changes in operating assets and liabilities		
Receivables	(87)	(76)
Receivables from affiliated companies	2	8
Inventory	1	(58)
Derivative collateral posted	(27)	38
Other assets	(10)	22
Income taxes, net	122	16
Accounts payable	98	16
Payables to affiliated companies	(6)	(7)
Other liabilities	28	14
Net cash provided by operating activities	610	445
Investing activities		
Gross property additions	(543)	(770)
Nuclear fuel additions	(13)	(18)
Purchases of available-for-sale securities and other investments	(3,505)	(415)
Proceeds from available-for-sale securities and other investments	3,508	420
Other investing activities	15	(4)
Net cash used by investing activities	(538)	(787)
Financing activities		
Dividends paid on preferred stock	(1)	(1)
Dividends paid to parent	(50)	-
Net decrease in short-term debt	-	(371)
Proceeds from issuance of long-term debt, net	591	-
Retirement of long-term debt	(300)	-
Changes in advances from affiliated companies	(214)	406
Contributions from parent	-	310
Other financing activities	(2)	(2)
Net cash provided by financing activities	24	342
Net increase in cash and cash equivalents	96	-
Cash and cash equivalents at beginning of period	17	19
Cash and cash equivalents at end of period	$113	$19
Supplemental disclosures		
Significant noncash transactions		
Accrued property additions	$113	$172

See Notes to Progress Energy Florida, Inc. Unaudited Condensed Interim Financial Statements.

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY d/b/a/ PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
COMBINED NOTES TO UNAUDITED CONDENSED INTERIM FINANCIAL STATEMENTS

INDEX TO APPLICABLE COMBINED NOTES TO UNAUDITED CONDENSED INTERIM FINANCIAL STATEMENTS BY REGISTRANT

Each of the following combined notes to the unaudited condensed interim financial statements of the Progress Registrants are applicable to Progress Energy, Inc. but not to each of PEC and PEF. The following table sets forth which notes are applicable to each of PEC and PEF. The notes that are not listed below for PEC or PEF are not, and shall not be deemed to be, part of PEC's or PEF's financial statements contained herein.

Registrant	Applicable Notes
PEC	1 through 9 and 11 through 13
PEF	1 through 9 and 11 through 13

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
COMBINED NOTES TO UNAUDITED INTERIM FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. ORGANIZATION

In this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. The information in these combined notes relates to each of the Progress Registrants as noted in the Index to Applicable Combined Notes to Unaudited Condensed Interim Financial Statements by Registrant. 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.

PROGRESS ENERGY

The Parent is a holding company headquartered in Raleigh, N.C. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 10 for further information about our segments.

PEC

PEC is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. PEC's subsidiaries are involved in insignificant nonregulated business activities. PEC is subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in west central Florida. PEF is subject to the regulatory jurisdiction of the Florida Public Service Commission (FPSC), the NRC and the FERC.

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and

Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for annual financial statements. The December 31, 2009 condensed balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. Because the accompanying interim financial statements do not include all of the information and footnotes required by GAAP for annual financial statements, they should be read in conjunction with the audited financial statements and notes thereto included in the Progress Registrants' annual report on Form 10-K for the fiscal year ended December 31, 2009 (2009 Form 10-K).

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis.

The amount of gross receipts tax, franchise taxes and other excise taxes included in electric operating revenues and taxes other than on income in the statements of income were as follows:

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Progress Energy	$ 81	$ 77	$ 164	$ 156
PEC	27	26	57	52
PEF	54	51	107	104

The amounts included in these financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary to fairly present the Progress Registrants' financial position and results of operations for the interim periods. Unless otherwise noted, all adjustments are normal and recurring in nature. Due to seasonal weather variations, the impact of regulatory orders received, and the timing of outages of electric generating units, especially nuclear-fueled units, the results of operations for interim periods are not necessarily indicative of amounts expected for the entire year or future periods.

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

Certain amounts for 2009 have been reclassified to conform to the 2010 presentation.

C. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. The variable interest holder who has both of the following has the controlling financial interest and is the primary beneficiary: (1) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (2) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. In performing our analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity.

In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance which made significant changes to the model for determining who should consolidate a VIE and addressed how often this assessment should be performed. The guidance was effective for us on January 1, 2010 (see Note 2). As a result of the adoption, we and PEC deconsolidated two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code (the Code) and recognized a $(2) million cumulative effect adjustment during the six months ended June 30, 2010.

PROGRESS ENERGY

Progress Energy, through its subsidiary PEC, is the managing member and primary beneficiary of, and consolidates a limited partnership which qualifies for federal affordable housing and historic tax credits under Section 42 of the Code. Our variable interests are debt and equity investments in the VIE. There were no changes to our assessment of the primary beneficiary during 2009 or for the period ended June 30, 2010. No financial or other support has been provided to the VIE during the periods presented.

The following table sets forth the carrying amount and classification of our investment in the partnership as reflected in the Consolidated Balance Sheets:

(in millions)	June 30, 2010	December 31, 2009
Miscellaneous other property and investments	$15	$17
Other assets and deferred debits	1	1
Accounts payable	5	4

The assets of the VIE are collateral for, and can only be used to settle, its obligations. The creditors of the VIE do not have recourse to our general credit or the general credit of PEC and there are no other arrangements that could expose us to losses.

Progress Energy, through its subsidiary PEC, has interests in two entities resulting from capital lease agreements. Both entities are VIEs and were established to lease buildings to PEC. Our maximum exposure to loss due to these capital lease agreements is a $7.5 million mandatory fixed price purchase option for one of the buildings. Total lease payments to these counterparties under the lease agreements were $1 million for the three and six months ended June 30, 2010 and 2009. We have requested the necessary information to consolidate these entities; both entities from which the necessary financial information was requested declined to provide the information to us, and, accordingly, we have applied the information scope exception provided by GAAP to the entities. We believe the effect of consolidating the entities would have an insignificant impact on our common stock equity, net earnings or cash flows. However, because we have not received any financial information from the counterparties, the impact cannot be determined at this time.

PEC

See discussion of PEC's variable interests in VIEs within the Progress Energy section.

PEF

PEF has no significant variable interests in VIEs.

D. SIGNIFICANT ACCOUNTING POLICIES

With the exception of the adoption of an accounting policy related to federal grants (discussed below) and new guidance relating to VIEs (See Note 2), there have been no material changes to our significant accounting policies, as compared to the significant accounting policies described in our 2009 Form 10-K.

FEDERAL GRANT

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency and renewable energy. On April 28, 2010, we accepted a grant from the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our Smart Grid initiatives. PEC and PEF each will receive up to $100 million over a three-year period as project work progresses. The DOE will provide reimbursement for 50 percent of allowable project costs, as incurred, up to the DOE's maximum obligation of $200 million. Projects funded by the grant must be completed by April 2013.

In accounting for the federal grant, we have elected to reduce the cost basis of applicable Smart Grid capital projects. Once these capital projects are placed into service, this election will reduce depreciation expense over the life of the assets. Other project costs incurred, which will be reimbursed by the DOE, are reflected in prepayments and other current assets on the Consolidated Balance Sheets.

We have incurred $60 million of allowable Smart Grid project costs through June 30, 2010. As of June 30, 2010, the reimbursable portion of these project costs are reflected in receivables, net and other current liabilities on the Consolidated Balance Sheets. On July 23, 2010, we submitted to the DOE our initial request for reimbursement of $30 million, which represents 50 percent of allowable Smart Grid project costs incurred.

2. NEW ACCOUNTING STANDARDS

CONSOLIDATIONS

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities." Subsequently, the FASB issued Accounting Standards Update (ASU) 2009-17, "Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," which codified SFAS No. 167 in the Accounting Standards Codification (ASC). This guidance made significant changes to the model for determining who should consolidate a VIE, addressed how often this assessment should be performed, required all existing arrangements with VIEs to be evaluated, and was adopted through a cumulative-effect adjustment. This guidance was effective for us on January 1, 2010. See Note 1C for information regarding our implementation of ASU 2009-17 and its impact on our and the Utilities' financial position and results of operations.

FAIR VALUE MEASUREMENT AND DISCLOSURES

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends ASC 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 was effective for us on January 1, 2010, with certain disclosures effective for periods beginning January 1, 2011. The initial adoption of ASU 2010-06 resulted in additional disclosure in the notes to the financial statements but did not have an impact on our or the Utilities' financial position or results of operations.

3. REGULATORY MATTERS

A. PEC RETAIL RATE MATTERS

FUEL COST RECOVERY

On June 4, 2010, PEC filed with the NCUC for a decrease in the fuel rate charged to its North Carolina ratepayers. PEC is asking the NCUC to approve a $170 million decrease in the fuel rates. This decrease is driven by declining fuel prices. If approved, the decrease would take effect December 1, 2010, and would reduce residential electric bills by $5.60 per 1,000 kWh for fuel recovery. As discussed under "Demand-side Management and Energy-efficiency Cost Recovery," PEC also filed with the NCUC for an increase in the demand-side management (DSM) and energy-efficiency (EE) rate. Additionally on June 4, 2010, PEC filed for a decrease in the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) rate, which if approved would take effect on December 1, 2010. If approved as filed, the net impact of the three filings would result in an average reduction in residential electric bills of 3.9 percent. We cannot predict the outcome of these matters.

On June 23, 2010, the SCPSC approved PEC's request for a decrease in the fuel rate charged to its South Carolina ratepayers. The $17 million decrease in fuel rates is driven by declining fuel prices. The decrease was effective July 1, 2010, and decreased residential electric bills by $2.73 per 1,000 kWh for fuel cost recovery. PEC also filed with the SCPSC for an increase in the DSM and EE rate effective July 1, 2010, which was approved on a provisional basis on June 30, 2010, pending review by the South Carolina Office of Regulatory Staff. If approved as filed, the net impact of the two filings would result in an average reduction in residential electric bills of 1.7 percent. We cannot predict the outcome of these matters.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

PEC is allowed to recover the costs of DSM and EE programs in North Carolina and South Carolina through an annual DSM and EE clause in each jurisdiction. The cost-recovery rider application in South Carolina has been approved by the SCPSC on a provisional basis pending a review by the South Carolina Office of Regulatory Staff.

PEC is allowed to capitalize DSM and EE costs intended to produce future benefits. In addition, the NCUC and the SCPSC have approved other forms of financial incentives for DSM and EE programs, including the recovery of net lost revenues and a performance incentive. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. EE programs include any equipment, physical or program change implemented after January 1, 2007, that results in less energy used to perform the same function. PEC has implemented a series of DSM and EE programs and will continue to pursue additional programs, which must be approved by the respective utility commissions. We cannot predict the outcome of DSM and EE filings currently pending approval or whether the implemented programs will produce the expected operational and economic results.

On June 4, 2010, PEC filed with the NCUC for an increase in the DSM and EE rate charged to its North Carolina ratepayers. PEC is asking the NCUC to approve a $31 million increase in the DSM and EE rates. If approved, the increase would take effect December 1, 2010, and would increase residential electric bills by $1.53 per 1,000 kWh for DSM and EE cost recovery. We cannot predict the outcome of this matter.

RENEWABLE ENERGY PORTFOLIO STANDARDS COST RECOVERY

PEC is required to file an annual NC REPS compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. Compliance with the NC REPS requirement is measured via renewable energy certificates (REC) earned after January 1, 2008. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, are participating in the REC tracking system, which came online July 1, 2010.

OTHER MATTERS

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

On October 22, 2009, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility will be in service by January 2013.

On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC intends to continue to depreciate these units using the current depreciation rates on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study.

On June 9, 2010, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. to replace the existing coal-fired generation at this site. PEC projects that the generating facility will be in service by late 2013 or early 2014.

B. PEF RETAIL RATE MATTERS

BASE RATES

On January 11, 2010, the FPSC approved a base rate increase for PEF of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. The FPSC authorized PEF the opportunity to earn a return on equity (ROE) of 10.5 percent. Subsequently, PEF filed petitions for a motion for reconsideration and approval of an accounting order with the FPSC.

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case and to an accounting order petition filed by PEF in 2010. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order and its accounting order petition. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. The settlement agreement also provides that PEF will have the discretion to reduce depreciation expense (cost of removal component) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in the cost of removal component of the depreciation reserve in 2012 until the earlier of (a) PEF's applicable cost of removal reserve reaches zero, or (b) the expiration of the settlement agreement at the end of 2012. In the event PEF reduces depreciation expense by less than the annual amounts for 2010 or 2011, PEF may carry forward (i.e., increase the annual cap by) any unused cost of removal reserve amounts in subsequent years during the term of the agreement. The balance of the cost of removal reserve is impacted by accruals in accordance with PEF's latest depreciation study, removal costs expended and reductions in depreciation expense as permitted by the settlement agreement. For the three and six months ended June 30, 2010, PEF recognized a $10 million reduction in depreciation expense pursuant to the settlement agreement. PEF's applicable cost of removal reserve of $516 million is recorded as a regulatory liability on its June 30, 2010 Balance Sheet. The settlement agreement also provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited, or interim base rate relief, or any combination thereof. Prior to requesting any such relief, PEF must have reflected on its referenced surveillance report associated depreciation expense reductions of at least $150 million. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost-recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the legislature or FPSC determines are clause recoverable, or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. PEF also may, at its discretion, accelerate in whole or in part the amortization of certain regulatory assets over the term of the settlement agreement. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period PEF can begin recovery, subject to refund, of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC.

On March 25, 2010, the FPSC opened a docket to review PEF's current allowance for funds used during construction (AFUDC) rate. On May 20, 2010, PEF filed with the FPSC prescribed schedules for the rolling twelve-month period ended March 31, 2010, with an effective date of April 1, 2010, based on its updated authorized ROE and all adjustments approved on January 11, 2010, in PEF's base rate case. The FPSC is scheduled to address this matter on August 31, 2010, with an order expected in September 2010. We cannot predict the outcome of this matter.

NUCLEAR COST RECOVERY

Levy Nuclear

In 2008, the FPSC granted PEF's petition for an affirmative Determination of Need and related orders requesting cost-recovery under Florida's nuclear cost-recovery rule for PEF's proposed Levy Units 1 and 2 nuclear power plants (Levy), together with the associated facilities, including transmission lines and substation facilities. Levy Units 1 and 2 are needed to maintain electric system reliability and integrity, provide fuel and generating diversity, and to allow PEF to continue to provide adequate electricity to its customers at a reasonable cost. The proposed Levy units will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities.

In PEF's 2010 nuclear cost-recovery filing (See "Cost Recovery"), PEF identified a schedule shift in the Levy project that resulted from the NRC's 2009 determination that certain schedule-critical work that PEF had proposed to perform within the scope of its Limited Work Authorization request submitted with the combined operating license (COL) application will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work anticipated in the initial schedule cannot begin until the COL is issued, resulting in a project shift of at least 20 months. Since then, regulatory and economic conditions identified in the 2010 nuclear cost-recovery filing have changed such that major construction activities on the Levy project are being postponed until after the NRC issues the COL, which is expected to be in late 2012 if the current licensing schedule remains on track. Taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification, we consider Levy to be PEF's preferred baseload generation option. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, public, regulatory and political support; adequate financial cost-recovery mechanisms; appropriate levels of joint owner participation; customer rate impacts; project feasibility, including comparison to other generation options, DSM and EE programs; and availability and terms of capital financing.

Crystal River Unit No. 3 Nuclear Plant Uprate

In 2007, the FPSC issued an order approving PEF's Determination of Need petition related to a multi-stage uprate of its Crystal River Unit No. 3 Nuclear Plant (CR3) that will increase CR3's gross output by approximately 180 MW by 2012. PEF implemented the first stage's design modifications in 2008. PEF will apply for the required license amendment for the third stage's design modification.

Cost Recovery

In 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the capacity cost-recovery clause (CCRC), which primarily consisted of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. The FPSC approved the alternate proposal allowing PEF to recover revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of $198 million of capacity revenues and the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

On April 30, 2010, PEF filed its annual nuclear cost-recovery filing with the FPSC to recover $164 million which includes recovery of pre-construction, carrying and CCRC recoverable operations and maintenance (O&M) costs incurred or anticipated to be incurred during 2011, recovery of $60 million of the 2009 deferral in 2011, as well as the estimated actual true-up of 2010 costs associated with the Levy and CR3 uprate projects. This results in an estimated decrease in the nuclear cost-recovery charge of $1.46 per 1,000 kWh for residential customers, which if approved, would begin with the first January 2011 billing cycle. The FPSC has scheduled hearings in this matter for August 24-27, 2010, with a decision expected in October 2010. We cannot predict the outcome of this matter.

CR3 OUTAGE

In September 2009, CR3 began an outage for normal refueling and maintenance as well as its uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure, which has resulted in an extension of the outage. After a comprehensive analysis, PEF has determined that the concrete delamination at CR3 was caused by redistribution of stresses on the containment wall that occurred when we created an opening to accommodate the replacement of the unit's steam generators. We are pursuing a detailed repair plan that would achieve the unit's return to service during the fourth quarter of 2010. The actual return to service date will be determined by a number of factors, including regulatory reviews with the NRC and other agencies as appropriate, emergent work, final engineering designs and testing, weather and other developments.

PEF maintains insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at CR3 through Nuclear Electric Insurance Limited (NEIL). This program provides insurance coverage, with a 12-week deductible period, for 52 weeks in the amount of $4.5 million per week. An additional 71 weeks of coverage is provided at 80 percent of the above weekly amount. PEF also maintains insurance coverage through an accidental property damage program, which provides insurance coverage with a $10 million deductible per claim. PEF notified NEIL of the claim related to the CR3 delamination event on October 15, 2009. NEIL has confirmed that the CR3 delamination event is a covered accident.

On June 28, 2010, PEF received a payment of $42 million from a periodic partial payment claim filed with NEIL, representing $15 million for repair costs and $27 million for replacement power costs. The $27 million received for replacement power costs was recorded as a reduction to the deferred fuel cost regulatory asset at June 30, 2010. At June 30, 2010, PEF's deferred fuel cost regulatory asset included $139 million related to replacement power costs associated with the extension of the CR3 outage, net of the $27 million in insurance proceeds received to date. PEF has incurred $79 million in repair costs through June 30, 2010. At June 30, 2010, PEF has recorded a $54 million receivable for insurance on its Balance Sheet, which represents the $79 million in repair costs less the $10 million deductible and applicable repair cost insurance proceeds received to date. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. PEF considers replacement power costs in excess of insurance coverage to be recoverable through its fuel cost-recovery clause. We cannot predict the outcome of the recovery of replacement power costs in excess of insurance coverage.

DEMAND-SIDE MANAGEMENT COST RECOVERY

On December 30, 2009, the FPSC ordered PEF and other Florida utilities to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. Under the order, PEF's aggregate conservation goals over the next ten years were: 1,183 Summer MW, 1,072 Winter MW, and 3,488 gigawatt-hours (GWh). PEF filed with the FPSC a motion for reconsideration to correct what we believed were oversights or errors. The FPSC subsequently revised the aggregate goals to 1,134 Summer MW, 1,058 Winter MW, and 3,205 GWh over the next ten years. On March 30, 2010, PEF filed a petition for approval of its proposed DSM plan and to authorize cost recovery through the Energy Conservation Cost Recovery Clause (ECCR). The estimated average annual program costs are approximately $484 million, which corresponds to an average annual residential customer electric bill impact of approximately $17 per 1,200 kWh. An agenda conference has been scheduled by the FPSC for August 31, 2010. We cannot predict the outcome of this matter.

4. EQUITY AND COMPREHENSIVE INCOME

A. EARNINGS PER COMMON SHARE

There are no material differences between our basic and diluted earnings per share amounts for the three and six months ended June 30, 2010 and 2009. The effects of restricted stock unit awards, performance share awards and stock options outstanding on diluted earnings per share are immaterial.

B. RECONCILIATION OF TOTAL EQUITY

PROGRESS ENERGY

The consolidated financial statements include the accounts of Progress Energy and its majority owned subsidiaries. Noncontrolling interests principally represent minority shareholders' proportionate share of the equity of a subsidiary and a VIE (See Note 1C).

The following table presents changes in total equity for the year to date:

(in millions)	Total Common Stock Equity	Noncontrolling Interests	Total Equity
Balance, December 31, 2009	$ 9,449	$ 6	$ 9,455
Net income (loss)(a)	370	(2)	368
Other comprehensive loss	(44)	-	(44)
Issuance of shares through offerings and stock-based compensation plans (See Note 4D)	443	-	443
Dividends declared	(361)	-	(361)
Distributions to noncontrolling interests	-	(2)	(2)
Balance, June 30, 2010	$ 9,857	$ 2	$ 9,859
Balance, December 31, 2008	$ 8,687	$ 6	$ 8,693
Net income (loss)(a)	356	(1)	355
Other comprehensive income	20	-	20
Issuance of shares through offerings and stock-based compensation plans (See Note 4D)	582	-	582
Dividends declared	(356)	-	(356)
Distributions to noncontrolling interests	-	(1)	(1)
Other	-	2	2
Balance, June 30, 2009	$ 9,289	$ 6	$ 9,295

(a) For the six months ended June 30, 2010, consolidated net income of $370 million includes $2 million attributable to preferred shareholders of subsidiaries, which is not a component of total equity and is excluded from the table above. For the six months ended June 30, 2009, consolidated net income of $357 million includes $2 million attributable to preferred shareholders of subsidiaries, which is not a component of total equity and is excluded from the table above.

PEC

The consolidated financial statements include the accounts of PEC and its majority owned subsidiaries. Noncontrolling interests principally represent minority shareholders' proportionate share of the equity of a VIE (see Note 1C).

The following table presents changes in total equity for the year to date:

(in millions)	Total Common Stock Equity	Noncontrolling Interests	Total Equity
Balance, December 31, 2009	$ 4,657	$ 3	$ 4,660
Net income (loss)	250	(3)	247
Other comprehensive loss	(14)		(14)
Issuance of shares through stock-based compensation plans	29	-	29
Dividends paid to parent	(50)	-	(50)
Preferred stock dividends at stated rate	(1)	-	(1)
Tax benefit dividend	(2)	-	(2)
Balance, June 30, 2010	$ 4,869	$ -	$ 4,869
Balance, December 31, 2008	$ 4,301	$ 4	$ 4,305
Net income (loss)	223	(1)	222
Other comprehensive income	4	-	4
Issuance of shares through stock-based compensation plans	29	-	29
Dividends paid to parent	(200)	-	(200)
Preferred stock dividends at stated rate	(1)	-	(1)
Tax benefit dividend	(2)	-	(2)
Balance, June 30, 2009	$ 4,354	$ 3	$ 4,357

PEF

Interim disclosures of changes in equity are required if the reporting entity has less than wholly-owned subsidiaries, of which PEF has none. Therefore, an equity reconciliation for PEF has not been provided.

C. COMPREHENSIVE INCOME

PROGRESS ENERGY

(in millions)	Three months ended June 30, 2010	2009
Net income	$180	$174
Other comprehensive income (loss)		
Reclassification adjustments included in net income		
Change in cash flow hedges (net of tax expense of $1 and $1, respectively)	2	2
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $- and $1, respectively)	1	1
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $28 and $(5), respectively)	(44)	8
Other (net of tax expense of $-)	1	-
Other comprehensive (loss) income	(40)	11
Comprehensive income	140	185
Comprehensive income attributable to noncontrolling interests	-	-
Comprehensive income attributable to controlling interests	$140	$185

(in millions)	Six months ended June 30, 2010	2009
Net income	$370	$357
Other comprehensive income (loss)		
Reclassification adjustments included in net income		
Change in cash flow hedges (net of tax expense of $2 and $2, respectively)	3	3
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $1 and $1, respectively)	2	2
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $32 and $(9), respectively)	(50)	14
Other (net of tax expense of $-)	1	1
Other comprehensive (loss) income	(44)	20
Comprehensive income	326	377
Comprehensive income attributable to noncontrolling interests	-	(1)
Comprehensive income attributable to controlling interests	$326	$376

PEC

(in millions)	Three months ended June 30, 2010	2009
Net income	$111	$94
Other comprehensive income (loss)		
Reclassification adjustments included in net income		
Change in cash flow hedges (net of tax expense of $1 and $1, respectively)	1	2
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $10 and $(2), respectively)	(15)	2
Other comprehensive (loss) income	(14)	4
Comprehensive income	97	98
Comprehensive loss attributable to noncontrolling interests	1	1
Comprehensive income attributable to controlling interests	$98	$99

(in millions)	Six months ended June 30, 2010	2009
Net income	$247	$222
Other comprehensive income (loss)		
Reclassification adjustments included in net income		
Change in cash flow hedges (net of tax expense of $1 and $1, respectively)	2	2
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $10 and $(2), respectively)	(16)	2
Other comprehensive (loss) income	(14)	4
Comprehensive income	233	226
Comprehensive loss attributable to noncontrolling interests	3	1
Comprehensive income attributable to controlling interests	$236	$227

PEF

(in millions)	Three months ended June 30, 2010	2009
Net income	$119	$119
Other comprehensive income (loss)		
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $4 and $(2), respectively)	(7)	3
Other comprehensive (loss) income	(7)	3
Comprehensive income	$112	$122

(in millions)	Six months ended June 30, 2010	2009
Net income	$221	$208
Other comprehensive income (loss)		

Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $7 and $(2), respectively)	(10)	3
Other comprehensive (loss) income	(10)	3
Comprehensive income	$211	$211

D. COMMON STOCK

At June 30, 2010 and December 31, 2009, we had 500 million shares of common stock authorized under our charter, of which 293 million shares and 281 million shares, respectively, were outstanding. We periodically issue shares of common stock through the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)), the Progress Energy Investor Plus Plan (IPP) and for other benefit plans.

The following table presents information for our common stock issuances:

	Three months ended June 30,			
	2010		2009	
(in millions)	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	5.4	$208	-	$-
Issuances through 401(k) and/or IPP	5.4	208	-	-

	Six months ended June 30,			
	2010		2009	
(in millions)	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	11.5	$405	15.5	$545
Issuances under an underwritten public offering(a)	-	-	14.4	523
Issuances through 401(k) and/or IPP	10.7	405	0.6	22

(a) The shares issued under an underwritten public offering were issued on January 12, 2009, at a public offering price of $37.50.

5. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default for an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

6. DEBT AND CREDIT FACILITIES

Material changes, if any, to Progress Energy's, PEC's and PEF's debt and credit facilities and financing activities since December 31, 2009, are as follows.

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

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

7. FAIR VALUE DISCLOSURES

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.641 billion and $12.457 billion at June 30, 2010 and December 31, 2009, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $14.2 billion and $13.4 billion at June 30, 2010 and December 31, 2009, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants as discussed in Note 4C of the 2009 Form 10-K. NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at June 30, 2010 and December 31, 2009:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
June 30, 2010			
Common stock equity securities	$ 785	$ 30	$ 242
Preferred stock and other equity securities	17	-	6
Corporate debt securities	95	-	6
U.S. state and municipal debt securities	124	2	4
U.S. and foreign government debt securities	256	1	13
Money market funds and other securities	99	-	1
Total	$ 1,376	$ 33	$ 272
December 31, 2009			
Common stock equity securities	$ 839	$ 22	$ 301
Preferred stock and other equity securities	16	-	5
Corporate debt securities	71	1	5
U.S. state and municipal debt securities	118	2	3
U.S. and foreign government debt securities	197	1	8
Money market funds and other securities	161	-	-
Total	$ 1,402	$ 26	$ 322

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and unrealized gains for 2010 and 2009 relate to the NDT funds. There were no material unrealized losses and unrealized gains for the other available-for-sale debt securities held in benefit trusts at June 30, 2010 and December 31, 2009.

The aggregate fair value of investments that related to the June 30, 2010 and December 31, 2009 unrealized losses was $192 million and $209 million, respectively.

At June 30, 2010, the fair value of our available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$21
Due after one through five years	232
Due after five through 10 years	141
Due after 10 years	96
Total	$490

The following table presents selected information about our sales of available-for-sale securities. Realized gains and losses were determined on a specific identification basis.

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Proceeds	$1,755	$222	$3,692	$903
Realized gains	6	3	10	15
Realized losses	10	22	16	74

Proceeds were primarily related to NDT funds. Losses for investments in the benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At June 30, 2010 and December 31, 2009, 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 $3.694 billion and $3.709 billion at June 30, 2010 and December 31, 2009, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.1 billion and $4.0 billion at June 30, 2010 and December 31, 2009, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEC's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEC's nuclear plants as discussed in Note 4C of the 2009 Form 10-K. NDT funds are presented on the Consolidated Balance Sheets at fair value.

The following table summarizes PEC's available-for-sale securities at June 30, 2010 and December 31, 2009:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
June 30, 2010			
Common stock equity securities	$504	$22	$149
Preferred stock and other equity securities	11	-	4
Corporate debt securities	70	-	5
U.S. state and municipal debt securities	42	-	1
U.S. and foreign government debt securities	212	1	12
Money market funds and other securities	22	-	1
Total	$861	$23	$172
December 31, 2009			
Common stock equity securities	$545	$19	$186
Preferred stock and other equity securities	10	-	3
Corporate debt securities	67	1	4
U.S. state and municipal debt securities	37	-	1
U.S. and foreign government debt securities	177	1	8
Money market funds and other securities	35	-	-
Total	$871	$21	$202

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2010 and 2009 relate to the NDT funds.

The aggregate fair value of investments that related to the June 30, 2010 and December 31, 2009 unrealized losses was $110 million and $121 million, respectively.

At June 30, 2010, the fair value of PEC's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 17
Due after one through five years	182
Due after five through 10 years	85
Due after 10 years	47
Total	$ 331

The following table presents selected information about PEC's sales of available-for-sale securities. Realized gains and losses were determined on a specific identification basis.

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Proceeds	$ 115	$ 83	$ 222	$ 477
Realized gains	3	1	6	5
Realized losses	7	9	12	30

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PEC's proceeds were primarily related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At June 30, 2010 and December 31, 2009, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.481 billion and $4.183 billion at June 30, 2010 and December 31, 2009, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $5.1 billion and $4.5 billion at June 30, 2010 and December 31, 2009, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEF's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEF's nuclear plant as discussed in Note 4C of the 2009 Form 10-K. The NDT funds are presented on the Balance Sheets at fair value.

The following table summarizes PEF's available-for-sale securities at June 30, 2010 and December 31, 2009:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
June 30, 2010			
Common stock equity securities	$ 281	$ 8	$ 93
Preferred stock and other equity securities	6	-	2
Corporate debt securities	13	-	1
U.S. state and municipal debt securities	81	2	3
U.S. and foreign government debt securities	31	-	1
Money market funds and other securities	67	-	-
Total	$ 479	$ 10	$ 100
December 31, 2009			
Common stock equity securities	$ 294	$ 3	$ 115
Preferred stock and other equity securities	6	-	2
Corporate debt securities	4	-	1
U.S. state and municipal debt securities	80	2	2
U.S. and foreign government debt securities	13	-	-
Money market funds and other securities	99	-	-
Total	$ 496	$ 5	$ 120

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2010 and 2009 relate to the NDT funds.

The aggregate fair value of investments that related to the June 30, 2010 and December 31, 2009 unrealized losses was $78 million and $56 million, respectively.

At June 30, 2010, the fair value of PEF's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$4
Due after one through five years	46
Due after five through 10 years	46
Due after 10 years	30
Total	$126

The following table presents selected information about PEF's sales of available-for-sale securities. Realized gains and losses were determined on a specific identification basis.

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Proceeds	$1,624	$120	$3,414	$370
Realized gains	3	2	4	9
Realized losses	3	13	4	44

PEF's proceeds were related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At June 30, 2010 and December 31, 2009, PEF did not have any other securities.

B. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Fair value measurements require the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods where quoted prices or other observable inputs are not available.

The following tables set forth, by level within the fair value hierarchy, our and the Utilities' financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

PROGRESS ENERGY

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$785	$-	$-	$785
Preferred stock and other equity	17	-	-	17
Corporate debt	-	83	-	83
U.S. state and municipal debt	-	124	-	124
U.S. and foreign government debt	101	142	-	243
Money market funds and other	2	87	-	89
Total nuclear decommissioning trust funds	905	436	-	1,341
Derivatives				
Commodity forward contracts	-	14	-	14
Interest rate contracts	-	1	-	1
Other marketable securities				
Corporate debt	-	12	-	12
U.S. state and municipal debt	-	1	-	1
U.S. and foreign government debt	1	12	-	13
Money market funds and other	22	10	-	32
Total assets	$928	$486	$-	$1,414
Liabilities				
Derivatives				
Commodity forward contracts	$-	$444	$62	$506
Interest rate contracts	-	63	-	63
Contingent value obligations derivatives	-	15	-	15
Total liabilities	$-	$522	$62	$584

PEC

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 504	$ -	$ -	$ 504
Preferred stock and other equity	11	-	-	11
Corporate debt	-	70	-	70
U.S. state and municipal debt	-	43	-	43
U.S. and foreign government debt	82	130	-	212
Money market funds and other	1	18	-	19
Total nuclear decommissioning trust funds	598	261	-	859
Derivatives				
Interest rate contracts	-	1	-	1
Other marketable securities	5	-	-	5
Total assets	$ 603	$ 262	$ -	$ 865
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 74	$ 42	$ 116
Interest rate contracts	-	20	-	20
Total liabilities	$ -	$ 94	$ 42	$ 136

PEF

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$281	$-	$-	$281
Preferred stock and other equity	6	-	-	6
Corporate debt	-	13	-	13
U.S. state and municipal debt	-	81	-	81
U.S. and foreign government debt	19	12	-	31
Money market funds and other	1	69	-	70
Total nuclear decommissioning trust funds	307	175	-	482
Derivatives				
Commodity forward contracts	-	14	-	14
Other marketable securities	3	-	-	3
Total assets	$310	$189	$-	$499
Liabilities				
Derivatives				
Commodity forward contracts	$-	$370	$20	$390
Interest rate contracts	-	12	-	12
Total liabilities	$-	$382	$20	$402

The determination of the fair values in the preceding tables incorporates various factors, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

Transfers in (out) of Levels 1, 2 or 3 represent existing assets or liabilities that were previously categorized as a higher level for which the inputs to the estimate became less observable or assets and liabilities that were previously classified as Level 2 or 3 for which the lowest significant input became more observable during the period. There were no significant transfers in (out) of Levels 1, 2 and 3 during the period. Transfers into and out of each level are measured at the end of the period.

Commodity forward contract derivatives and interest rate contract derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity forward contract derivatives and interest rate contract derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 9 for discussion of risk management activities and derivative transactions.

NDT funds reflect the assets of the Utilities' nuclear decommissioning trusts. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments and are classified within Level 2.

Other marketable securities primarily represent available-for-sale debt securities used to fund certain employee benefit costs.

We issued Contingent Value Obligations (CVOs) in connection with the acquisition of Florida Progress, as discussed in Note 15 of the 2009 Form 10-K. The CVOs are derivatives recorded at fair value based on quoted prices from a less-than-active market and are classified as Level 2.

A reconciliation of changes in the fair value of our and the Utilities' commodity derivative liabilities classified as Level 3 in the fair value hierarchy for the periods ended June 30 follows:

PROGRESS ENERGY

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Derivatives, net at beginning of period	$52	$43	$39	$41
Total losses (gains), realized and unrealized deferred as regulatory assets and liabilities, net	10	(12)	23	(10)
Derivatives, net at end of period	$62	$31	$62	$31

PEC

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Derivatives, net at beginning of period	$36	$23	$27	$22
Total losses (gains), realized and unrealized deferred as regulatory assets and liabilities, net	6	(4)	15	(3)
Derivatives, net at end of period	$42	$19	$42	$19

PEF

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009

Derivatives, net at beginning of period	$16	$20	$12	$19
Total losses (gains), realized and unrealized				
deferred as regulatory assets and liabilities, net	4	(8)	8	(7)
Derivatives, net at end of period	$20	$12	$20	$12

Substantially all unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment. There were no Level 3 purchases, sales, issuances or settlements during the period.

8. BENEFIT PLANS

We have noncontributory defined benefit retirement plans that provide pension benefits for substantially all full-time employees. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria.

The components of the net periodic benefit cost for the respective Progress Registrants for the three months ended June 30 were:

PROGRESS ENERGY

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2010	2009	2010	2009
Service cost	$ 12	$ 10	$ 2	$ 2
Interest cost	35	34	8	9
Expected return on plan assets	(39)	(35)	(1)	(1)
Amortization of actuarial loss(a)	12	12	-	1
Other amortization, net (a)	2	2	1	1
Net periodic cost before deferral(b)	$ 22	$ 23	$ 10	$ 12

(a) Adjusted to reflect PEF's rate treatment. See Note 16B in the 2009 Form 10-K.
(b) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. For the three months ended June 30, 2009, PEF deferred $16 million of net periodic pension costs as a regulatory asset. See Notes 7C and 16A in the 2009 Form 10-K.

PEC

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2010	2009	2010	2009
Service cost	$5	$4	$1	$1
Interest cost	16	16	4	5
Expected return on plan assets	(19)	(17)	-	(1)
Amortization of actuarial loss	4	2	-	1
Other amortization, net	1	1	-	-
Net periodic cost	$7	$6	$5	$6

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PEF

(in millions)	Pension Benefits 2010	2009	Other Postretirement Benefits 2010	2009
Service cost	$5	$5	$-	$1
Interest cost	15	14	3	3
Expected return on plan assets	(17)	(15)	-	-
Amortization of actuarial loss	7	9	-	-
Other amortization, net	-	-	1	1
Net periodic cost before deferral(a)	$10	$13	$4	$5

(a) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. For the three months ended June 30, 2009, PEF deferred $16 million of net periodic pension costs as a regulatory asset. See Notes 7C and 16A in the 2009 Form 10-K.

The components of the net periodic benefit cost for the respective Progress Registrants for the six months ended June 30 were:

PROGRESS ENERGY

(in millions)	Pension Benefits 2010	2009	Other Postretirement Benefits 2010	2009
Service cost	$23	$21	$4	$4
Interest cost	70	68	16	18
Expected return on plan assets	(78)	(69)	(2)	(3)
Amortization of actuarial loss(a)	25	24	1	2
Other amortization, net (a)	3	3	2	3
Net periodic cost before deferral(b)	$43	$47	$21	$24

(a) Adjusted to reflect PEF's rate treatment. See Note 16B in the 2009 Form 10-K.
(b) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. For the six months ended June 30, 2009, PEF deferred $16 million of net periodic pension costs as a regulatory asset. See Notes 7C and 16A in the 2009 Form 10-K.

PEC

(in millions)	Pension Benefits 2010	2009	Other Postretirement Benefits 2010	2009
Service cost	$9	$8	$2	$3
Interest cost	32	31	8	9
Expected return on plan assets	(38)	(34)	(1)	(2)
Amortization of actuarial loss	8	4	-	1
Other amortization, net	3	3	1	1
Net periodic cost	$14	$12	$10	$12

PEF

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2010	2009	2010	2009
Service cost	$10	$9	$1	$1
Interest cost	29	28	6	7
Expected return on plan assets	(34)	(29)	(1)	(1)
Amortization of actuarial loss	15	18	-	1
Other amortization, net	-	-	2	2
Net periodic cost before deferral(a)	$20	$26	$8	$10

(a) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. For the six months ended June 30, 2009, PEF deferred $16 million of net periodic pension costs as a regulatory asset. See Notes 7C and 16A in the 2009 Form 10-K.

In 2010, contributions directly to pension plan assets are expected to approximate $–––129 million for us, including $95 million for PEC and $34 million for PEF. We contributed $13 million during the six months ended June 30, 2010, including $7 million for PEC and $6 million for PEF.

The Patient Protection and Affordable Care Act (PPACA) and the related Health Care and Education Reconciliation Act, which made various amendments to the PPACA, were enacted in March 2010. The PPACA contains a provision that changes the tax treatment related to a federal subsidy available to sponsors of retiree health benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy (RDS). Employers are not currently taxed on the RDS payments they receive. However, as a result of the PPACA as amended, RDS payments will effectively become taxable in tax years beginning after December 31, 2012, by requiring the amount of the subsidy received to be offset against the employer's deduction for health care expenses. Under GAAP, changes in tax law are accounted for in the period of enactment. Accordingly, an additional tax expense of $22 million for us, $12 million for PEC and $10 million for PEF has been recognized during the six months ended June 30, 2010.

We are still evaluating the additional impacts of the PPACA as amended; however, we do not expect the changes to have a significant impact on the benefit obligations we have recorded.

9. RISK MANAGEMENT ACTIVITIES AND DERIVATIVE TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions.

The Utilities have financial derivative instruments with settlement dates through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2010 and 2011. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled. After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have posted or held cash collateral in support of these instruments. Progress Energy had a cash collateral asset included in derivative collateral posted of $194 million and $146 million on the Progress Energy Consolidated Balance Sheets at June 30, 2010 and December 31, 2009, respectively. At June 30, 2010, Progress Energy had 244.0 million MMBtu notional of natural gas and 32.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

PEC had a cash collateral asset included in prepayments and other current assets of $20 million and $7 million on the PEC Consolidated Balance Sheets at June 30, 2010 and December 31, 2009, respectively. At June 30, 2010, PEC had 50.4 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases.

PEF’s cash collateral asset included in derivative collateral posted was $174 million and $139 million on the PEF Balance Sheets at June 30, 2010 and December 31, 2009, respectively. At June 30, 2010, PEF had 193.6 million MMBtu notional of natural gas and 32.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. At June 30, 2010, we had 1.2 million gallons notional of gasoline, of which there was 0.6 million gallons each at PEC and PEF, and 1.2 million gallons notional of diesel, of which there was 0.6 million gallons each at PEC and PEF related to outstanding commodity derivative swaps that were entered into to hedge forecasted gasoline and diesel purchases. Realized gains and losses are recorded net as part of fleet vehicle fuel costs. At June 30, 2010 and December 31, 2009, neither we nor the Utilities had material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our or the Utilities’ results of operations for the three and six months ended June 30, 2010 and 2009.

At June 30, 2010 and December 31, 2009, the amount recorded in our or the Utilities' accumulated other comprehensive income related to commodity cash flow hedges was not material.

B. INTEREST RATE DERIVATIVES – FAIR VALUE OR CASH FLOW HEDGES

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. Our cash flow hedging strategies are primarily accomplished through the use of forward starting swaps and our fair value hedging strategies are primarily accomplished through the use of fixed-to-floating swaps. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

At June 30, 2010, all open interest rate hedges will reach their mandatory termination dates within three and a half years. At June 30, 2010, including amounts related to terminated hedges, we had $81 million of after-tax losses, including $41 million and $7 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive income related to forward starting swaps. It is expected that in the next twelve months losses of $7 million, net of tax, primarily related to terminated hedges, will be reclassified to interest expense at Progress Energy, including $4 million at PEC. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of changes in interest rates and changes in the timing of debt issuances at the Parent and the Utilities and changes in market value of currently open forward starting swaps.

At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses, including $27 million of after-tax losses at PEC and $3 million of after-tax gains at PEF, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million at PEC and $75 million at PEF. At June 30, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million at PEC and $200 million at PEF.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At June 30, 2010, and December 31, 2009, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with Moody's Investors Service, Inc. (Moody's), Standard & Poor's Rating Services (S&P) and Fitch Ratings (Fitch). Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from Moody's, S&P and Fitch. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

The aggregate fair value of all derivative instruments at Progress Energy with credit risk-related contingent features that are in a net liability position at June 30, 2010 is $492 million, for which Progress Energy has posted collateral of $194 million in the normal course of business. If the credit risk-related contingent features underlying these agreements were triggered at June 30, 2010, Progress Energy would have been required to post an additional $298 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEC with credit risk-related contingent features that are in a liability position at June 30, 2010 is $116 million, for which PEC has posted collateral of $20 million in the normal course of business. If the credit risk-related contingent features underlying these agreements were triggered at June 30, 2010, PEC would have been required to post an additional $96 million of collateral with its counterparties.

The aggregate fair value of all derivative instruments at PEF with credit risk-related contingent features that are in a net liability position at June 30, 2010 is $376 million, for which PEF has posted collateral of $174 million in the normal course of business. If the credit risk-related contingent features underlying these agreements were triggered on June 30, 2010, PEF would have been required to post an additional $202 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

PROGRESS ENERGY

The following table presents the fair value of derivative instruments at June 30, 2010 and December 31, 2009:

Instrument / Balance sheet location	June 30, 2010		December 31, 2009	
(in millions)	Asset	Liability	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Prepayments and other current assets	$ -		$ 5	
Other assets and deferred debits	1		14	
Derivative liabilities, current		$ 32		$ -
Derivative liabilities, long-term		31		-
Total derivatives designated as hedging instruments	1	63	19	-
Derivatives not designated as hedging instruments				
Commodity derivatives(a)				
Prepayments and other current assets	9		11	
Other assets and deferred debits	5		9	
Derivative liabilities, current		217		189
Derivative liabilities, long-term		289		236
CVOs(b)				
Other liabilities and deferred credits		15		15
Fair value of derivatives not designated as hedging instruments	14	521	20	440
Fair value loss transition adjustment(c)				
Derivative liabilities, current		1		1
Derivative liabilities, long-term		4		4
Total derivatives not designated as hedging instruments	14	526	20	445
Total derivatives	$ 15	$ 589	$ 39	$ 445

(a) Substantially all of these contracts receive regulatory treatment.
(b) As discussed in Note 15 of the 2009 Form 10-K, the Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000.
(c) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings

over the term of the related contracts.

The following tables present the effect of derivative instruments on other comprehensive income (OCI) (See Note 4C) and the Consolidated Statements of Income for the three months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	2009
Interest rate derivatives(c) (d)	$(44)	$8	$(2)	$(2)	$-	$-

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	2009	Unrealized Gain or (Loss)(b) 2010	2009
Commodity derivatives(a)	$ (91)	$ (185)	$ (2)	$ 77

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives 2010	2009
Commodity derivatives(a)	$1	$1
Fair value loss transition adjustment(a)	-	1
CVOs(a)	-	1
Total	$1	$3

(a) Amounts recorded in the Consolidated Statements of Income are classified in other, net.

The following tables present the effect of derivative instruments on OCI (See Note 4C) and the Consolidated Statements of Income for the six months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	2009
Commodity cash flow derivatives	$ -	$ 1	$ -	$ -	$ -	$ -
Interest rate derivatives(c) (d)	(50)	13	(3)	(3)	-	(3)
Total	$ (50)	$ 14	$ (3)	$ (3)	$ -	$ (3)

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	2009	Unrealized Gain or (Loss)(b) 2010	2009
Commodity derivatives(a)	$(150)	$(312)	$(236)	$(264)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives 2010	2009
Fair value loss transition adjustment(a)	$-	$1
CVOs(a)	-	8
Total	$-	$9

(a) Amounts recorded in the Consolidated Statements of Income are classified in other, net.

PEC

The following table presents the fair value of derivative instruments at June 30, 2010 and December 31, 2009:

Instrument / Balance sheet location (in millions)	June 30, 2010 Asset	June 30, 2010 Liability	December 31, 2009 Asset	December 31, 2009 Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Other assets and deferred debits	$1		$8	
Derivative liabilities, current		$9		$-
Other liabilities and deferred credits		11		-
Total derivatives designated as hedging instruments	1	20	8	-
Derivatives not designated as hedging instruments				
Commodity derivatives(a)				
Derivative liabilities, current		38		28
Other liabilities and deferred credits		78		62
Fair value of derivatives not designated as hedging instruments	-	116	-	90
Fair value loss transition adjustment(b)				
Derivative liabilities, current		1		1
Other liabilities and deferred credits		4		4
Total derivatives not designated as hedging instruments	-	121	-	95
Total derivatives	$1	$141	$8	$95

(a) Substantially all of these contracts receive regulatory treatment.
(b) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contracts.

The following tables present the effect of derivative instruments on OCI (See Note 4C) and the Consolidated Statements of Income for the three months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	2009
Interest rate derivatives(c) (d)	$ (15)	$ 2	$ (1)	$ (2)	$ -	$ -

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	2009	Unrealized Gain or (Loss)(b) 2010	2009
Commodity derivatives	$(12)	$(21)	$(2)	$7

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives 2010	2009
Commodity derivatives(a)	$1	$1
Fair value loss transition adjustment(a)	-	1
Total	$1	$2

(a) Amounts recorded in the Consolidated Statements of Income are classified in other, net.

The following tables present the effect of derivative instruments on OCI (See Note 4C) and the Consolidated Statements of Income for the six months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	2009
Interest rate derivatives(c) (d)	$(16)	$2	$(2)	$(2)	$-	$(2)

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	2009	Unrealized Gain or (Loss)(b) 2010	2009
Commodity derivatives	$(19)	$(39)	$(44)	$(40)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives 2010	2009
Fair value loss transition adjustment(a)	$-	$1

(a) Amounts recorded in the Consolidated Statements of Income are classified in other, net.

PEF

The following table presents the fair value of derivative instruments at June 30, 2010 and December 31, 2009:

Instrument / Balance sheet location	June 30, 2010		December 31, 2009	
(in millions)	Asset	Liability	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Prepayments and other current assets	$ -		$ 5	
Derivative liabilities, long-term		$ 12		$ -
Total derivatives designated as hedging instruments	-	12	5	-
Derivatives not designated as hedging instruments				
Commodity derivatives(a)				
Prepayments and other current assets	9		11	
Other assets and deferred debits	5		9	
Derivative liabilities, current		179		161
Derivative liabilities, long-term		211		174
Total derivatives not designated as hedging instruments	14	390	20	335
Total derivatives	$ 14	$ 402	$ 25	$ 335

(a) Substantially all of these contracts receive regulatory treatment.

The following tables present the effect of derivative instruments on OCI (See Note 4C) and the Statements of Income for the three months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	2009
Interest rate derivatives(c) (d)	$ (7)	$ 3	$ -	$ -	$ -	$ -

(a) Effective portion.

(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Three Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	Realized Gain or (Loss)(a) 2009	Unrealized Gain or (Loss)(b) 2010	Unrealized Gain or (Loss)(b) 2009
Commodity derivatives	$(79)	$(164)	$-	$70

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

The following tables present the effect of derivative instruments on OCI (See Note 4C) and the Statements of Income for the six months ended June 30, 2010 and 2009:

Derivatives Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2010	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives(a) 2009	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2010	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income(a) 2009	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2010	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives(b) 2009
Interest rate derivatives(c) (d)	$ (10)	$ 3	$ -	$ -	$ -	$ -

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(d) Amounts recorded in the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments for the Six Months Ended June 30,

Instrument (in millions)	Realized Gain or (Loss)(a) 2010	Realized Gain or (Loss)(a) 2009	Unrealized Gain or (Loss)(b) 2010	Unrealized Gain or (Loss)(b) 2009
Commodity derivatives	$(131)	$(273)	$(192)	$(224)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

10. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
At and for the three months ended June 30, 2010					
Revenues					
Unaffiliated	$ 1,117	$ 1,252	$ 3	$ -	$ 2,372
Intersegment	-	-	53	(53)	-
Total revenues	1,117	1,252	56	(53)	2,372
Ongoing Earnings (loss)	112	119	(50)	-	181
Assets	13,966	13,693	20,690	(16,212)	32,137
For the three months ended June 30, 2009					
Revenues					
Unaffiliated	$ 1,076	$ 1,234	$ 2	$ -	$ 2,312
Intersegment	-	-	55	(55)	-
Total revenues	1,076	1,234	57	(55)	2,312
Ongoing Earnings (loss)	94	121	(34)	-	181
At and for the six months ended June 30, 2010					
Revenues					
Unaffiliated	$ 2,380	$ 2,522	$ 5	$ -	$ 4,907
Intersegment	-	-	114	(114)	-
Total revenues	2,380	2,522	119	(114)	4,907
Ongoing Earnings (loss)	260	232	(97)	-	395
Assets	13,966	13,693	20,690	(16,212)	32,137
For the six months ended June 30, 2009					
Revenues					
Unaffiliated	$ 2,254	$ 2,496	$ 4	$ -	$ 4,754
Intersegment	-	-	120	(120)	-
Total revenues	2,254	2,496	124	(120)	4,754
Ongoing Earnings (loss)	223	212	(72)	-	363

Management uses the non-GAAP financial measure “Ongoing Earnings” as a performance measure to evaluate the results of our segments and operations. Ongoing Earnings is computed as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Management has identified the following Ongoing Earnings adjustments: tax levelization, which increases or decreases the tax expense recorded in the reporting period to reflect the annual projected tax rate, because it has no impact on annual earnings; CVO mark-to-market adjustments because we are unable to predict changes in their fair value; and the impact from changes in the tax treatment of the Medicare Part D subsidy because GAAP requires that the impact of the tax law change be accounted for in the period of enactment rather than the affected tax year. Additionally, management has determined that impairments, charges (and subsequent adjustments, if any) recognized for the retirement of generating units prior to the end of their estimated useful lives and operating results of discontinued operations are not representative of our ongoing operations and should be excluded in computing Ongoing Earnings.

Reconciliations of consolidated Ongoing Earnings to net income attributable to controlling interests follow:

(in millions)	For the three months ended June 30, 2010	2009
Ongoing Earnings	$181	$181
Tax levelization	-	(5)
CVO mark-to-market (Note 9D)	-	1
Impairment, net of tax benefit of $1	(1)	(2)
Plant retirement adjustment, net of tax expense of $-	1	-
Income from continuing operations before cumulative effect of change in accounting principle	181	175
Discontinued operations, net of tax	(1)	(1)
Net income attributable to controlling interests	$180	$174

(in millions)	For the six months ended June 30, 2010	2009
Ongoing Earnings	$395	$363
Tax levelization	(2)	(12)
CVO mark-to-market (Note 9D)	-	8
Impairment, net of tax benefit of $1	(2)	(2)
Plant retirement adjustment, net of tax expense of $1	1	-
Change in tax treatment of the Medicare Part D subsidy (Note 8)	(22)	-
Continuing income attributable to noncontrolling interests, net of tax	2	1
Income from continuing operations before cumulative effect of change in accounting principle	372	358
Discontinued operations, net of tax	-	(1)
Cumulative effect of change in accounting principle, net of tax	(2)	-
Net income attributable to noncontrolling interests, net of tax	-	(1)
Net income attributable to controlling interests	$370	$356

11. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. The components of other, net as shown on the accompanying Statements of Income were as follows:

PROGRESS ENERGY

(in millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Nonregulated energy and delivery services income, net	$8	$8	$7	$9
CVOs unrealized gain, net	-	1	-	8
Donations	(2)	(2)	(6)	(5)
Other, net	(1)	6	(1)	-
Other, net	$5	$13	$-	$12

PEC

(in millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Nonregulated energy and delivery services income, net	$6	$6	$2	$4
Donations	(1)	(2)	(3)	(3)
Other, net	(1)	-	(2)	(4)
Other, net	$4	$4	$(3)	$(3)

PEF

(in millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Nonregulated energy and delivery services income, net	$2	$3	$5	$6
Donations	(1)	(1)	(2)	(3)
Other, net	-	5	-	4
Other, net	$1	$7	$3	$7

12. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. HAZARDOUS AND SOLID WASTE

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. A discussion of sites by legal entity follows.

We measure our liability for environmental sites based on available evidence, including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

The following tables contain information about accruals for probable and estimable costs related to various environmental sites, which were included in other current liabilities and other liabilities and deferred credits on the Balance Sheets:

PROGRESS ENERGY

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2009	$ 22	$ 20	$ 42
Amount accrued for environmental loss contingencies(a)	4	10	14
Expenditures for environmental loss contingencies(b)	(7)	(9)	(16)
Balance, June 30, 2010(c)	$ 19	$ 21	$ 40
Balance, December 31, 2008	$ 31	$ 22	$ 53
Amount accrued for environmental loss contingencies(a)	4	2	6
Expenditures for environmental loss contingencies(b)	(6)	(7)	(13)
Balance, June 30, 2009(c)	$ 29	$ 17	$ 46

(a) Amounts accrued are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010, we accrued $2 million for the remediation of MGP and other sites and $8 million for the remediation of distribution and substation transformers. For the three months ended June 30, 2009, our accruals for the remediation of MGP and other sites and for the remediation of distribution and substation transformers were not material.

(b) Expenditures are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010, we spent $5 million for the remediation of MGP and other sites and $5 million for the remediation of distribution and substation transformers. For the three months ended June 30, 2009 our expenditures for the remediation of MGP and other sites and for the remediation of distribution and substation transformers were not material.

(c) Expected to be paid out over one to 15 years.

PEC

(in millions)	MGP and Other Sites
Balance, December 31, 2009	$13
Amount accrued for environmental loss contingencies(a)	2
Expenditures for environmental loss contingencies(b)	(3)
Balance, June 30, 2010(c)	$12
Balance, December 31, 2008	$16
Amount accrued for environmental loss contingencies(a)	4
Expenditures for environmental loss contingencies(b)	(4)
Balance, June 30, 2009(c)	$16

(a) Amounts accrued are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010 and 2009, PEC's accruals for the remediation of MGP and other sites were not material.

(b) Expenditures are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010 and 2009, PEC's expenditures for the remediation of MGP and other sites were not material.

(c) Expected to be paid out over one to five years.

PEF

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2009	$ 9	$ 20	$ 29
Amount accrued for environmental loss contingencies(a)	2	10	12
Expenditures for environmental loss contingencies(b)	(4)	(9)	(13)
Balance, June 30, 2010(c)	$ 7	$ 21	$ 28
Balance, December 31, 2008	$ 15	$ 22	$ 37
Amount accrued for environmental loss contingencies(a)	-	2	2
Expenditures for environmental loss contingencies(b)	(2)	(7)	(9)
Balance, June 30, 2009(c)	$ 13	$ 17	$ 30

(a) Amounts accrued are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010, PEF accrued $2 million for the remediation of MGP and other sites and $8 million for the remediation of distribution and substation transformers. For the three months ended June 30, 2009, PEF's accruals for the remediation of MGP and other sites and for the remediation of distribution and substation transformers were not material.

(b) Expenditures are for the six months ended June 30, 2010 and 2009. For the three months ended June 30, 2010, PEF spent $4 million for the remediation of MGP and other sites and $5 million for the remediation of distribution and substation transformers. For the three months ended June 30, 2009, PEF's expenditures for the remediation of MGP and other sites and for the remediation of distribution and substation transformers were not material.

(c) Expected to be paid out over one to 15 years.

PROGRESS ENERGY

In addition to PEC's Ward Transformer site located in Raleigh, N.C. (Ward), PEF's distribution and substation transformers sites, and the Utilities' MGP sites discussed below, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 13B).

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PEC

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At June 30, 2010 and December 31, 2009, PEC's recorded liability for the site was approximately $5 million and $4 million, respectively. In 2008 and 2009, PEC filed civil actions against PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. On March 24, 2010, the federal district court in which this matter is pending denied motions to dismiss filed by a number of defendants, but granted several other motions filed by state agencies and successor entities. The court also set a trial date for May 7, 2012. On June 15, 2010, the court entered a case management order and discovery is proceeding. The outcome of these matters cannot be predicted.

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

PEF

The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

PEF has received approval from the FPSC for recovery through the Environmental Cost Recovery Clause (ECRC) of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should additional distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC. At June 30, 2010 and December 31, 2009, PEF has recorded a regulatory asset for the probable recovery of costs through the ECRC related to the sites included under the agreement with the FDEP.

B. AIR AND WATER QUALITY

At June 30, 2010 and December 31, 2009, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEF's CAIR projects have been placed in service.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, in response to petitions for rehearing filed by a number of parties, the D.C. Court of Appeals remanded the CAIR without vacating the rule for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. On August 2, 2010, the EPA published the proposed Transport Rule, which is the regulatory program that will replace the CAIR when finalized. The proposed Transport Rule contains new emissions trading programs for nitrogen oxides (NOx) and sulfur dioxide (SO2) emissions as well as more stringent overall emissions targets. The EPA plans to finalize the Transport Rule in the spring of 2011. Due to significant investments in NOx and SO2 emissions controls and fleet modernization projects completed or underway, we believe both PEC and PEF are well positioned to comply with the Transport Rule. The outcome of the EPA's rulemaking cannot be predicted. Because the D.C. Court of Appeals' December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for NOx and SO2 for BART-affected units under the CAVR. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO2 emissions in addition to particulate matter emissions for BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard consistent with the agency's original listing determination. In addition, North Carolina adopted a state specific requirement. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5). The CR4 project was placed in service in May 2010 and the CR5 project was placed in service on December 2, 2009. Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was originally anticipated to be around 2020. As discussed in Note 3B, PEF identified in its 2010 nuclear cost-recovery filing regulatory and economic conditions causing schedule shifts such that major construction activities are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of these developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. Emission allowances are included on the Balance Sheets in inventory and in other assets and deferred debits and have not changed materially from what was reported in the 2009 Form 10-K.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. On June 21, 2010, the EPA proposed two options for new rules to regulate coal combustion products. The first option would create a comprehensive program of federally-enforceable requirements for coal combustion products management and disposal as hazardous waste. The other option would have the EPA set performance standards for coal combustion products management facilities and regulate disposal of coal combustion products as non-hazardous waste. The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. The 90-day public comment period ends on September 20, 2010, and a final rule is expected in 2011. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

13. COMMITMENTS AND CONTINGENCIES

Contingencies and significant changes to the commitments discussed in Note 22 in the 2009 Form 10-K are described below.

A. PURCHASE OBLIGATIONS

As part of our ordinary course of business, we and the Utilities enter into various long- and short-term contracts for fuel requirements at our generating plants. Significant changes from the commitment amounts reported in Note 22A in the 2009 Form 10-K can result from new contracts, changes in existing contracts along with the impact of fluctuations in current estimates of future market prices for those contracts that are market price indexed. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels, and other financial commitments. Additional commitments for fuel and related transportation will be required to supply the Utilities' future needs. At June 30, 2010, our and the Utilities' contractual cash obligations and other commercial commitments have not changed materially from what was reported in the 2009 Form 10-K except as follows.

PEC

In April 2010, PEC entered into a conditional agreement for firm pipeline transportation capacity to support PEC's gas supply needs for the approximate period of June 2013 through May 2033. The total cost to PEC associated with this agreement is estimated to be approximately $477 million. The agreement is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of this agreement, the estimated costs are not currently considered a fuel commitment of PEC.

PEF

PEF's construction obligations included in Note 22A to the 2009 Form 10-K, which were primarily comprised of contractual obligations related to the Levy Engineering, Procurement, and Construction (EPC) agreement, totaled $1.455 billion, $2.981 billion, $2.818 billion and $1.543 billion, respectively, for less than one year, one to three years, three to five years and more than five years from December 31, 2009. We executed an amendment to the EPC agreement in 2010 because of schedule shifts in the Levy project (See Note 3B), and will postpone major construction activities on the project until after the NRC issues the COL, which is expected to be in late 2012 if the licensing schedule remains on track. Therefore, we will defer substantially all expenditures under the EPC agreement until the COL is received. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict the timing of when those obligations will be satisfied or the magnitude of any change. Additionally, in light of the schedule shifts, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work will be suspended on the remaining long lead time equipment items and PEF will be in suspension negotiations with the selected equipment vendors in the coming months. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. We cannot predict the outcome of this matter.

On June 30, 2010, PEF entered into a long-term service agreement for the Hines Energy Complex covering scheduled maintenance events through 2029. The total cost to PEF associated with this agreement is estimated to be approximately $390 million over the term of the agreement.

B. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At June 30, 2010, 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 June 30, 2010, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At June 30, 2010, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $308 million, including $32 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. At June 30, 2010 and December 31, 2009, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $33 million and $34 million, respectively. These amounts included $7 million for PEF at June 30, 2010 and December 31, 2009. During the six months ended June 30, 2010, our and the Utilities' accruals and expenditures related to guarantees and indemnifications were not material. 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 in guarantees for certain payments of two wholly owned indirect subsidiaries (See Note 14).

C. OTHER COMMITMENTS AND CONTINGENCIES

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims. The Utilities have asserted nearly $91 million in damages incurred between January 31, 1998, and December 31, 2005, the time period set by the court for damages in this case. The Utilities may file subsequent damage claims as they incur additional costs.

In 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. A request for reconsideration filed by the United States Department of Justice resulted in an immaterial reduction of the award. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000, (the Asset Purchase Agreement) by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (renamed Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global had requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities and (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations.

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations. In December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. On December 16, 2009, we filed notice of appeal. We are continuing to pursue the appellate process, but cannot predict the outcome of this matter.

In a second suit filed in the Superior Court for Wake County, N.C., Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC (the North Carolina Global Case), the Progress Affiliates seek declaratory relief consistent with our interpretation of the Asset Purchase Agreement. Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress

Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the verdict in the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

NOTICE OF VIOLATION

On April 29, 2009, the EPA issued a notice of violation and opportunity to show cause with respect to a 16,000-gallon oil spill at one of PEC's substations in 2007. The notice of violation did not include specified sanctions sought. Subsequently, the EPA notified PEC that the agency is seeking monetary sanctions that are de minimus to our and PEC's results of operations or financial condition. PEC has entered into consent agreements with the EPA on two of the three issues. Discussions between PEC and the EPA to resolve the remaining issue are ongoing. We cannot predict the outcome of this matter.

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. On April 6, 2010, PEF filed a motion to dismiss the complaint. The trial judge issued an order on May 3, 2010, dismissing the complaint. The plaintiffs filed an amended complaint on June 1, 2010. PEF believes the lawsuit is without merit and filed a motion to dismiss the amended complaint on July 12, 2010. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

14. CONDENSED CONSOLIDATING STATEMENTS

As discussed in Note 23 in the 2009 Form 10-K, we have guaranteed certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and as disclosed in Note 11B in the 2009 Form 10-K, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a VIE of which we are not the primary beneficiary. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only, which is primarily comprised of its wholly owned subsidiary PEF. The Non-guarantor Subsidiaries column includes the consolidated financial results of all non-guarantor subsidiaries, which is primarily comprised of our wholly owned subsidiary PEC. The Other column includes elimination entries for all intercompany transactions and other consolidation adjustments. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-Q. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities.

Condensed Consolidating Statement of Income
Three months ended June 30, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$-	$1,255	$1,117	$-	$2,372
Affiliate revenues	-	-	52	(52)	-
Total operating revenues	-	1,255	1,169	(52)	2,372
Operating expenses					
Fuel used in electric generation	-	368	375	-	743
Purchased power	-	239	76	-	315
Operation and maintenance	-	208	347	(50)	505
Depreciation, amortization and accretion	-	110	123	-	233
Taxes other than on income	-	83	51	(1)	133
Other	-	3	-	-	3
Total operating expenses	-	1,011	972	(51)	1,932
Operating income (loss)	-	244	197	(1)	440
Other income (expense)					
Interest income	2	-	2	(3)	1
Allowance for equity funds used during construction	-	10	15	-	25
Other, net	-	-	3	2	5
Total other income (expense), net	2	10	20	(1)	31
Interest charges					
Interest charges	72	75	54	(2)	199
Allowance for borrowed funds used during construction	-	(2)	(5)	-	(7)
Total interest charges, net	72	73	49	(2)	192
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(70)	181	168	-	279
Income tax (benefit) expense	(28)	67	57	2	98
Equity in earnings of consolidated subsidiaries	222	-	-	(222)	-
Income (loss) from continuing operations	180	114	111	(224)	181
Discontinued operations, net of tax	-	-	(1)	-	(1)
Net income (loss)	180	114	110	(224)	180
Net (income) loss attributable to noncontrolling interests, net of tax	-	(1)	1	-	-
Net income (loss) attributable to controlling interests	$180	$113	$111	$(224)	$180

Condensed Consolidating Statement of Income
Three months ended June 30, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$-	$1,236	$1,076	$-	$2,312
Affiliate revenues	-	-	54	(54)	-
Total operating revenues	-	1,236	1,130	(54)	2,312
Operating expenses					
Fuel used in electric generation	-	443	383	-	826
Purchased power	-	200	57	-	257
Operation and maintenance	2	204	331	(53)	484
Depreciation, amortization and accretion	-	105	121	-	226
Taxes other than on income	-	80	51	(1)	130
Other	-	8	2	-	10
Total operating expenses	2	1,040	945	(54)	1,933
Operating (loss) income	(2)	196	185	-	379
Other income (expense)					
Interest income	3	1	1	(3)	2
Allowance for equity funds used during construction	-	29	7	-	36
Other, net	1	6	5	1	13
Total other income (expense), net	4	36	13	(2)	51
Interest charges					
Interest charges	58	71	54	(2)	181
Allowance for borrowed funds used during construction	-	(9)	(3)	-	(12)
Total interest charges, net	58	62	51	(2)	169
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(56)	170	147	-	261
Income tax (benefit) expense	(26)	55	53	4	86
Equity in earnings of consolidated subsidiaries	204	-	-	(204)	-
Income (loss) from continuing operations	174	115	94	(208)	175
Discontinued operations, net of tax	-	-	(1)	-	(1)
Net income (loss)	174	115	93	(208)	174
Net (income) loss attributable to noncontrolling interests, net of tax	-	-	1	(1)	-
Net income (loss) attributable to controlling interests	$174	$115	$94	$(209)	$174

Condensed Consolidating Statement of Income
Six months ended June 30, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 2,527	$ 2,380	$ -	$ 4,907
Affiliate revenues	-	-	113	(113)	-
Total operating revenues	-	2,527	2,493	(113)	4,907
Operating expenses					
Fuel used in electric generation	-	781	858	-	1,639
Purchased power	-	452	126	-	578
Operation and maintenance	3	413	676	(107)	985
Depreciation, amortization and accretion	-	234	245	-	479
Taxes other than on income	-	176	115	(4)	287
Other	-	5	-	-	5
Total operating expenses	3	2,061	2,020	(111)	3,973
Operating (loss) income	(3)	466	473	(2)	934
Other income (expense)					
Interest income	4	-	3	(4)	3
Allowance for equity funds used during construction	-	18	28	-	46
Other, net	(1)	3	(4)	2	-
Total other income (expense), net	3	21	27	(2)	49
Interest charges					
Interest charges	143	145	106	(4)	390
Allowance for borrowed funds used during construction	-	(7)	(9)	-	(16)
Total interest charges, net	143	138	97	(4)	374
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(143)	349	403	-	609
Income tax (benefit) expense	(58)	136	154	5	237
Equity in earnings of consolidated subsidiaries	455	-	-	(455)	-
Income (loss) from continuing operations before cumulative effect of change in accounting principle	370	213	249	(460)	372
Discontinued operations, net of tax	-	1	(1)	-	-
Cumulative effect of change in accounting principle, net of tax	-	-	(2)	-	(2)

Net income (loss)	370	214	246	(460)	370
Net (income) loss attributable to noncontrolling interests, net of tax	-	(2)	3	(1)	-
Net income (loss) attributable to controlling interests	$ 370	$ 212	$ 249	$ (461)	$ 370

Condensed Consolidating Statement of Income
Six months ended June 30, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$-	$2,500	$2,254	$-	$4,754
Affiliate revenues	-	-	119	(119)	-
Total operating revenues	-	2,500	2,373	(119)	4,754
Operating expenses					
Fuel used in electric generation	-	955	825	-	1,780
Purchased power	-	360	114	-	474
Operation and maintenance	3	406	642	(114)	937
Depreciation, amortization and accretion	-	265	241	-	506
Taxes other than on income	-	168	109	(4)	273
Other	-	10	2	-	12
Total operating expenses	3	2,164	1,933	(118)	3,982
Operating (loss) income	(3)	336	440	(1)	772
Other income (expense)					
Interest income	6	2	4	(6)	6
Allowance for equity funds used during construction	-	59	16	-	75
Other, net	8	6	(2)	-	12
Total other income (expense), net	14	67	18	(6)	93
Interest charges					
Interest charges	110	143	113	(6)	360
Allowance for borrowed funds used during construction	-	(18)	(6)	-	(24)
Total interest charges, net	110	125	107	(6)	336
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(99)	278	351	(1)	529
Income tax (benefit) expense	(39)	76	129	5	171
Equity in earnings of consolidated subsidiaries	415	-	-	(415)	-
Income (loss) from continuing operations	355	202	222	(421)	358
Discontinued operations, net of tax	1	(1)	(1)	-	(1)
Net income (loss)	356	201	221	(421)	357
Net (income) loss attributable to noncontrolling interests, net of tax	-	(1)	1	(1)	(1)
Net income (loss) attributable to controlling interests	$356	$200	$222	$(422)	$356

Condensed Consolidating Balance Sheet
June 30, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$-	$9,977	$10,424	$111	$20,512
Current assets					
Cash and cash equivalents	366	116	208	-	690
Notes receivable from affiliated companies	133	51	9	(193)	-
Regulatory assets	-	223	101	-	324
Derivative collateral posted	-	174	20	-	194
Income taxes receivable	15	6	33	(33)	21
Prepayments and other current assets	19	1,248	1,334	(170)	2,431
Total current assets	533	1,818	1,705	(396)	3,660
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,669	-	-	(13,669)	-
Regulatory assets	-	1,317	894	-	2,211
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	482	859	-	1,341
Other assets and deferred debits	165	225	918	(550)	758
Total deferred debits and other assets	13,834	2,024	2,671	(10,564)	7,965
Total assets	$14,367	$13,819	$14,800	$(10,849)	$32,137
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$9,857	$4,727	$5,270	$(9,997)	$9,857
Noncontrolling interests	-	2	-	-	2
Total equity	9,857	4,729	5,270	(9,997)	9,859
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	115	(152)	272
Long-term debt, net	3,494	4,481	3,688	1	11,664
Total capitalization	13,351	9,553	9,132	(10,148)	21,888
Current liabilities					
Current portion of long-term debt	700	-	6	(1)	705
Notes payable to affiliated companies	-	166	27	(193)	-
Derivative liabilities	23	179	48	-	250
Other current liabilities	259	1,147	943	(201)	2,148
Total current liabilities	982	1,492	1,024	(395)	3,103
Deferred credits and other liabilities					
Noncurrent income tax liabilities	-	371	1,327	(410)	1,288
Regulatory liabilities	-	1,060	1,307	112	2,479
Other liabilities and deferred credits	34	1,343	2,010	(8)	3,379
Total deferred credits and other liabilities	34	2,774	4,644	(306)	7,146
Total capitalization and liabilities	$14,367	$13,819	$14,800	$(10,849)	$32,137

Condensed Consolidating Balance Sheet
December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 9,733	$ 9,886	$ 114	$ 19,733
Current assets					
Cash and cash equivalents	606	72	47	-	725
Notes receivable from affiliated companies	30	46	303	(379)	-
Regulatory assets	-	54	88	-	142
Derivative collateral posted	-	139	7	-	146
Income taxes receivable	5	97	50	(7)	145
Prepayments and other current assets	14	1,158	1,377	(176)	2,373
Total current assets	655	1,566	1,872	(562)	3,531
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,348	-	-	(13,348)	-
Regulatory assets	-	1,307	873	(1)	2,179
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	496	871	-	1,367
Other assets and deferred debits	166	202	923	(520)	771
Total deferred debits and other assets	13,514	2,005	2,667	(10,214)	7,972
Total assets	$ 14,169	$ 13,304	$ 14,425	$ (10,662)	$ 31,236
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 9,449	$ 4,590	$ 5,085	$ (9,675)	$ 9,449
Noncontrolling interests	-	3	3	-	6
Total equity	9,449	4,593	5,088	(9,675)	9,455
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	115	(152)	272
Long-term debt, net	4,193	3,883	3,703	-	11,779
Total capitalization	13,642	8,819	8,965	(9,827)	21,599
Current liabilities					
Current portion of long-term debt	100	300	6	-	406
Short-term debt	140	-	-	-	140
Notes payable to affiliated companies	-	376	3	(379)	-
Derivative liabilities	-	161	29	-	190
Other current liabilities	261	941	902	(182)	1,922

Total current liabilities	501	1,778	940	(561)	2,658
Deferred credits and other liabilities					
Noncurrent income tax liabilities	-	320	1,258	(382)	1,196
Regulatory liabilities	-	1,103	1,293	114	2,510
Other liabilities and deferred credits	26	1,284	1,969	(6)	3,273
Total deferred credits and other liabilities	26	2,707	4,520	(274)	6,979
Total capitalization and liabilities	$ 14,169	$ 13,304	$ 14,425	$ (10,662)	$ 31,236

Condensed Consolidating Statement of Cash Flows
Six months ended June 30, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$ 54	$ 582	$ 694	$ (171)	$ 1,159
Investing activities					
Gross property additions	-	(543)	(598)	25	(1,116)
Nuclear fuel additions	-	(13)	(106)	-	(119)
Purchases of available-for-sale securities and other investments	-	(3,507)	(308)	-	(3,815)
Proceeds from available-for-sale securities and other investments	-	3,509	283	-	3,792
Changes in advances to affiliated companies	(103)	(5)	294	(186)	-
Return of investment in consolidated subsidiaries	54	-	-	(54)	-
Contributions to consolidated subsidiaries	(56)	-	-	56	-
Other investing activities	-	14	-	-	14
Net cash used by investing activities	(105)	(545)	(435)	(159)	(1,244)
Financing activities					
Issuance of common stock, net	405	-	-	-	405
Dividends paid on common stock	(354)	-	-	-	(354)
Dividends paid to parent	-	(102)	(50)	152	-
Dividends paid to parent in excess of retained earnings	-	-	(54)	54	-
Net decrease in short-term debt	(140)	-	-	-	(140)
Proceeds from issuance of long-term debt, net	-	591	-	-	591
Retirement of long-term debt	(100)	(300)	-	-	(400)
Changes in advances from affiliated companies	-	(210)	24	186	-
Contributions from parent	-	33	37	(70)	-
Other financing activities	-	(6)	(54)	8	(52)
Net cash (used) provided by financing activities	(189)	6	(97)	330	50
Net (decrease) increase in cash and cash equivalents	(240)	43	162	-	(35)
Cash and cash equivalents at beginning of period	606	72	47	-	725
	$ 366	$ 115	$ 209	$ -	$ 690

Cash and cash equivalents at end of period

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Condensed Consolidating Statement of Cash Flows
Six months ended June 30, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$169	$454	$670	$(198)	$1,095
Investing activities					
Gross property additions	-	(770)	(411)	9	(1,172)
Nuclear fuel additions	-	(18)	(42)	-	(60)
Proceeds from sales of assets to affiliated companies	-	-	7	(7)	-
Purchases of available-for-sale securities and other investments	-	(420)	(562)	-	(982)
Proceeds from available-for-sale securities and other investments	-	423	537	-	960
Changes in advances to affiliated companies	(329)	(56)	(43)	428	-
Return of investment in consolidated subsidiaries	12	-	-	(12)	-
Contributions to consolidated subsidiaries	(347)	-	-	347	-
Other investing activities	-	(1)	(1)	(1)	(3)
Net cash (used) provided by investing activities	(664)	(842)	(515)	764	(1,257)
Financing activities					
Issuance of common stock, net	545	-	-	-	545
Dividends paid on common stock	(347)	-	-	-	(347)
Dividends paid to parent	-	(1)	(200)	201	-
Dividends paid to parent in excess of retained earnings	-	-	(12)	12	-
Payments of short-term debt with original maturities greater than 90 days	(129)	-	-	-	(129)
Net decrease in short-term debt	(40)	(371)	(110)	-	(521)
Proceeds from issuance of long-term debt, net	742	-	595	-	1,337
Retirement of long-term debt	-	-	(400)	-	(400)
Changes in advances from affiliated companies	-	417	11	(428)	-
Contributions from parent	-	343	17	(360)	-
Other financing activities	1	(5)	(56)	9	(51)
Net cash provided (used) by financing activities	772	383	(155)	(566)	434
Net increase (decrease) in cash and cash equivalents	277	(5)	-	-	272
Cash and cash equivalents at beginning of period	88	73	19	-	180
Cash and cash equivalents at end of period	$365	$68	$19	$-	$452

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is separately filed by Progress Energy, Inc. (Progress Energy), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF). As used in this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. Neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

The following MD&A contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors" found within Part II of this Form 10-Q and Item 1A, "Risk Factors" to the Progress Registrant's annual report on Form 10-K for the fiscal year ended December 31, 2009 (2009 Form 10-K) for a discussion of the factors that may impact any such forward-looking statements made herein.

Amounts reported in the interim statements of income are not necessarily indicative of amounts expected for the respective annual or future periods due to the effects of weather variations and the timing and scope of outages of electric generating units, especially nuclear-fueled units, among other factors.

MD&A includes financial information prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), as well as certain non-GAAP financial measures, "Ongoing Earnings" and "Base Revenues," discussed below. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The non-GAAP financial measures should be viewed as a supplement to and not a substitute for financial measures presented in accordance with GAAP. Non-GAAP measures as presented herein may not be comparable to similarly titled measures used by other companies.

This discussion should be read in conjunction with the accompanying financial statements found elsewhere in this report and in conjunction with the 2009 Form 10-K.

PROGRESS ENERGY

RESULTS OF OPERATIONS

In this section, we provide analysis and discussion of earnings and the factors affecting earnings on both a GAAP and non-GAAP basis. We introduce our results of operations in an overview section followed by a more detailed analysis and discussion by business segment.

We compute our non-GAAP financial measurement "Ongoing Earnings" as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP.

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

(in millions except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Three months ended June 30, 2010					
Ongoing Earnings	$ 112	$ 119	$ (50)	$ 181	$ 0.63
Impairment, net of tax(a)	(1)	-	-	(1)	(0.01)
Plant retirement adjustment, net of tax(a)	1	-	-	1	-
Discontinued operations attributable to controlling interests, net of tax	-	-	(1)	(1)	-
Net income (loss) attributable to controlling interests	$ 112	$ 119	$ (51)	$ 180	$ 0.62
Three months ended June 30, 2009					
Ongoing Earnings	$ 94	$ 121	$ (34)	$ 181	$ 0.64
Tax levelization	1	(2)	(4)	(5)	(0.02)
CVO mark-to-market	-	-	1	1	0.01
Impairment, net of tax(a)	-	-	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	-	-	(1)	(1)	-
Net income (loss) attributable to controlling interests	$ 95	$ 119	$ (40)	$ 174	$ 0.62
Six months ended June 30, 2010					
Ongoing Earnings	$ 260	$ 232	$ (97)	$ 395	$ 1.37
Tax levelization	2	(2)	(2)	(2)	-
Impairment, net of tax(a)	(2)	-	-	(2)	-
Plant retirement adjustment, net of tax(a)	1	-	-	1	
Change in the tax treatment of the Medicare Part D subsidy	(12)	(10)	-	(22)	(0.08)
Net income (loss) attributable to controlling interests(b)	$ 249	$ 220	$ (99)	$ 370	$ 1.29
Six months ended June 30, 2009					
Ongoing Earnings	$ 223	$ 212	$ (72)	$ 363	$ 1.30
Tax levelization	(1)	(5)	(6)	(12)	(0.04)
CVO mark-to-market	-	-	8	8	0.03
Impairment, net of tax(a)	-	-	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	-	-	(1)	(1)	-
Net income (loss) attributable to controlling interests(b)	$ 222	$ 207	$ (73)	$ 356	$ 1.28

(a) Calculated using assumed tax rate of 40 percent.
(b) Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $(1) million at both PEC and PEF.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings (See Note 10).

OVERVIEW

For the three months ended June 30, 2010, our net income attributable to controlling interests was $180 million, or $0.62 per share, compared to net income attributable to controlling interests of $174 million, or $0.62 per share, for the same period in 2009. The increase as compared to prior year was primarily due to:

- favorable weather at the Utilities;
- higher returns earned on nuclear cost-recovery and environmental cost recovery clause (ECRC) assets at PEF; and
- increased retail base rates at PEF.

Offsetting these items were:

- unfavorable allowance for funds used during construction (AFUDC) equity at PEF;
- higher operation and maintenance (O&M) expenses at the Utilities; and
- lower wholesale base revenues at PEF.

For the six months ended June 30, 2010, our net income attributable to controlling interests was $370 million, or $1.29 per share, compared to net income attributable to controlling interests of $356 million, or $1.28 per share, for the same period in 2009. The increase as compared to prior year was primarily due to:

- favorable weather at the Utilities;
- higher returns earned on nuclear cost-recovery and ECRC assets at PEF;
- increased retail base rates at PEF; and
- favorable AFUDC equity at PEC.

Offsetting these items were:

- unfavorable AFUDC equity at PEF;
- higher O&M expenses at the Utilities;
- lower wholesale base revenues at the Utilities; and
- unfavorable change in the tax treatment of the Medicare Part D subsidy at the Utilities (Ongoing Earnings adjustment).

PROGRESS ENERGY CAROLINAS

PEC contributed net income available to parent totaling $112 million and $95 million for the three months ended June 30, 2010 and 2009, respectively. The increase in net income available to parent for the three months ended June 30, 2010, compared to the same period in 2009, was primarily due to the favorable impact of weather, favorable AFUDC equity, favorable retail customer growth and usage, higher miscellaneous revenues and lower other operating expenses, partially offset by higher O&M expenses. PEC contributed Ongoing Earnings of $112 million and $94 million for the three months ended June 30, 2010 and 2009, respectively. The 2010 Ongoing Earnings adjustments to net income available to parent were due to PEC recording an impairment of certain miscellaneous investments, net of tax of $1 million offset by a plant retirement adjustment, net of tax of $1 million. The 2009 Ongoing Earnings adjustment to net income available to parent was due to PEC recording a tax levelization benefit of $1 million.

Management does not consider these items to be representative of PEC's fundamental core earnings and excluded these items in computing PEC's Ongoing Earnings.

PEC contributed net income available to parent totaling $249 million and $222 million for the six months ended June 30, 2010 and 2009, respectively. The increase in net income available to parent for the six months ended June 30, 2010, compared to the same period in 2009, was primarily due to the favorable impact of weather, favorable AFUDC equity, favorable retail customer growth and usage, higher miscellaneous revenues, lower interest expense and favorable tax levelization, partially offset by higher O&M expenses and the unfavorable change in the tax treatment of the Medicare Part D subsidy. PEC contributed Ongoing Earnings of $260 million and $223 million for the six months ended June 30, 2010 and 2009, respectively. The 2010 Ongoing Earnings adjustments to net income available to parent were due to PEC recording a $12 million charge for the change in the tax treatment of the Medicare Part D subsidy and an impairment of certain miscellaneous investments, net of tax of $2 million, partially offset by a tax levelization benefit of $2 million and a plant retirement adjustment, net of tax of $1 million. The 2009 Ongoing Earnings adjustment to net income available to parent was due to PEC recording a tax levelization charge of $1 million. Management does not consider these items to be representative of PEC's fundamental core earnings and excluded these items in computing PEC's Ongoing Earnings.

Three Months Ended June 30, 2010, Compared to Three Months Ended June 30, 2009

REVENUES

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEC consider Base Revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power expenses and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the return on asset component of demand-side management (DSM), energy-efficiency (EE) and renewable energy clause revenues. We and PEC have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by customer class, for the three months ended June 30 follows:

(in millions)

Customer Class	2010	Change	% Change	2009
Residential	$ 237	$ 8	3.5	$ 229
Commercial	170	2	1.2	168
Industrial	88	3	3.5	85
Governmental	14	1	7.7	13
Unbilled	43	6	-	37
Total retail base revenues	552	20	3.8	532
Wholesale base revenues	69	(3)	(4.2)	72
Total Base Revenues	621	17	2.8	604
Clause recoverable regulatory returns	3	1	50.0	2
Miscellaneous	30	4	15.4	26
Fuel and other pass-through revenues	463	19	-	444
Total operating revenues	$ 1,117	$ 41	3.8	$ 1,076

PEC's total Base Revenues were $621 million and $604 million for the three months ended June 30, 2010 and 2009, respectively. The $17 million increase in Base Revenues was due primarily to the $17 million favorable impact of weather and the $4 million favorable impact of retail customer growth and usage, partially offset by $3 million lower wholesale revenues. The favorable impact of weather was driven by 22 percent higher cooling degree days than 2009. Additionally, cooling degree days were 44 percent higher than normal. The favorable impact of retail customer growth and usage was driven by an increase in the average usage per retail customer and a net 11,000 increase in the average number of customers for 2010 compared to 2009.

PEC's miscellaneous revenues increased $4 million in 2010 primarily due to higher transmission rates.

PEC's electric energy sales in kilowatt-hours (kWh) and the percentage change by customer class for the three months ended June 30 were as follows:

(in millions of kWh)

Customer Class	2010	Change	% Change	2009
Residential	3,707	116	3.2	3,591
Commercial	3,337	47	1.4	3,290
Industrial	2,674	112	4.4	2,562
Governmental	369	12	3.4	357
Unbilled	712	78	-	634
Total retail kWh sales	10,799	365	3.5	10,434
Wholesale	3,157	(102)	(3.1)	3,259
Total kWh sales	13,956	263	1.9	13,693

The increase in retail kWh sales in 2010 was primarily due to favorable weather as previously discussed. The decrease in wholesale kWh sales in 2010 was primarily due to lower excess generation sales driven by unfavorable market dynamics and favorable weather, which limited sales opportunities.

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $451 million for the three months ended June 30, 2010, which represents an $11 million increase compared to the same period in 2009. Purchased power expense increased $19 million to $76 million compared to the same period in 2009 primarily due to higher system requirements resulting from favorable weather. Fuel used in electric generation decreased $8 million to $375 million primarily due to $46 million lower deferred fuel expense, partially offset by the $30 million impact of a change in generation mix resulting from nuclear plant outages and the $8 million impact of higher system requirements resulting from favorable weather. The decrease in deferred fuel expense was primarily due to higher fuel and purchased power expenses and lower fuel rates.

Operation and Maintenance

O&M expense was $300 million for the three months ended June 30, 2010, which represents a $17 million increase compared to the same period in 2009. This increase was primarily due to $25 million higher nuclear plant outage and maintenance costs, partially offset by $7 million lower fossil steam plant outage and maintenance costs. The higher nuclear plant outage and maintenance costs are primarily due to the larger scope of outages and more emergent work in 2010 as compared to 2009.

Other

Other operating expenses consisted of a gain of $1 million and losses of $2 million for the three months ended June 30, 2010 and 2009, respectively, primarily due to land sales.

Total Other Income, Net

Total other income, net was $20 million for the three months ended June 30, 2010, which represents an $8 million increase compared to the same period in 2009. This increase was primarily due to favorable AFUDC equity of $8 million resulting from increased eligible construction project costs.

Income Tax Expense

Income tax expense increased $6 million for the three months ended June 30, 2010, as compared to the same period in 2009, primarily due to the $9 million impact of higher pre-tax income, partially offset by the $3 million impact of the increase in AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense. PEC's income tax expense was decreased by $1 million for the three months ended June 30, 2009, compared to no impact for the same period in 2010 related to the impact of tax levelization. GAAP requires companies to apply a levelized effective income tax rate to interim periods that is consistent with the estimated annual effective tax rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Because this adjustment will vary each quarter, but will have no effect on net income for the year, management does not consider this adjustment to be representative of PEC's fundamental core earnings. Therefore, the impact of tax levelization is excluded in computing PEC's Ongoing Earnings.

Six Months Ended June 30, 2010, Compared to Six Months Ended June 30, 2009

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by customer class, for the six months ended June 30 follows:

(in millions)

Customer Class	2010	Change	% Change	2009
Residential	$593	$41	7.4	$552
Commercial	343	2	0.6	341
Industrial	168	1	0.6	167
Governmental	28	1	3.7	27
Unbilled	9	9	-	-
Total retail base revenues	1,141	54	5.0	1,087
Wholesale base revenues	144	(14)	(8.9)	158
Total Base Revenues	1,285	40	3.2	1,245
Clause recoverable regulatory returns	4	-	-	4
Miscellaneous	66	8	13.8	58
Fuel and other pass-through revenues	1,025	78	-	947
Total operating revenues	$2,380	$126	5.6	$2,254

PEC's total Base Revenues were $1.285 billion and $1.245 billion for the six months ended June 30, 2010 and 2009, respectively. The $40 million increase in Base Revenues was due primarily to the $47 million favorable impact of weather and the $11 million favorable impact of retail customer growth and usage, partially offset by $14 million lower wholesale base revenues. The favorable impact of weather was driven by 19 percent higher cooling degree days and 15 percent higher heating degree days than 2009. Additionally, cooling degree days were 41 percent higher than normal and heating degree days were 12 percent higher than normal. The favorable impact of retail customer growth and usage was driven by an increase in the average usage per retail customer and a net 12,000 increase in the average number of customers for 2010 compared to 2009. The lower wholesale base revenues were primarily due to lower energy rates with a major customer.

PEC’s miscellaneous revenues increased $8 million in 2010 primarily due to higher transmission rates.

PEC's electric energy sales in kWh and the percentage change by customer class for the six months ended June 30 were as follows:

(in millions of kWh)

Customer Class	2010	Change	% Change	2009
Residential	9,595	866	9.9	8,729
Commercial	6,758	153	2.3	6,605
Industrial	5,119	137	2.7	4,982
Governmental	744	44	6.3	700
Unbilled	82	(88)	-	170
Total retail kWh sales	22,298	1,112	5.2	21,186
Wholesale	6,969	34	0.5	6,935
Total kWh sales	29,267	1,146	4.1	28,121

The increase in retail kWh sales in 2010 was primarily due to favorable weather as previously discussed. The increase in wholesale kWh sales in 2010 was primarily due to a new peaking contract, partially offset by lower excess generation sales driven by unfavorable market dynamics and favorable weather, which limited sales opportunities.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power expenses were $984 million for the six months ended June 30, 2010, which represents a $45 million increase compared to the same period in 2009. Fuel used in electric generation increased $33 million to $858 million primarily due to the $65 million impact of a change in generation mix resulting from nuclear plant outages and the $39 million impact of higher system requirements resulting from favorable weather, partially offset by $69 million lower deferred fuel expense. The decrease in deferred fuel expense was primarily due to higher fuel and purchased power expenses and lower fuel rates. Purchased power expense increased $12 million to $126 million compared to the same period in 2009 primarily due to higher system requirements resulting from favorable weather.

Operation and Maintenance

O&M expense was $585 million for the six months ended June 30, 2010, which represents a $43 million increase compared to the same period in 2009. This increase was primarily due to $30 million higher nuclear plant outage and maintenance costs, $9 million lower nuclear insurance refund, $6 million higher storm costs and $5 million higher emission expense primarily due to sales of nitrogen oxides (NOx) emission allowances in the prior year. These unfavorable items are partially offset by $6 million lower fossil steam plant outage and maintenance costs. The higher nuclear plant outage and maintenance costs are primarily due to the larger scope of outages and more emergent work in 2010 as compared to 2009.

Taxes Other Than on Income

Taxes other than on income was $111 million for the six months ended June 30, 2010, which represents a $6 million increase compared to the same period in 2009. This increase was primarily due to a $5 million increase in gross receipts taxes due to higher retail revenues as previously discussed. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expenses consisted of losses of $2 million for the six months ended June 30, 2009, primarily due to land sales.

Total Other Income, Net

Total other income, net was $27 million for the six months ended June 30, 2010, which represents an $11 million increase compared to the same period in 2009. This increase was primarily due to favorable AFUDC equity of $12 million resulting from increased eligible construction project costs.

Total Interest Charges, net

Total interest charges, net was $94 million for the six months ended June 30, 2010, which represents a $9 million decrease compared to the same period in 2009. This decrease was primarily due to the $4 million impact of lower average debt outstanding, the $3 million impact of lower variable rates on pollution control bonds and $3 million favorable AFUDC debt related to increased eligible construction project costs.

Income Tax Expense

Income tax expense increased $24 million for the six months ended June 30, 2010, as compared to the same period in 2009, primarily due to the $21 million impact of higher pre-tax income, the $12 million impact of the change in the tax treatment of the Medicare Part D subsidy resulting from recently enacted federal health care reform (See Note 8), and the $5 million impact of the favorable prior year tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified nuclear decommissioning trust (NDT) funds to qualified NDTs. These unfavorable items are partially offset by the $5 million impact of the increase in AFUDC equity and the $3 million impact of tax levelization. AFUDC equity is excluded from the calculation of income tax expense. GAAP requires companies to apply a levelized effective income tax rate to interim periods that is consistent with the estimated annual effective tax rate. PEC’s income tax expense was decreased by $2 million for the six months ended June 30, 2010, compared to an increase of $1 million for the six months ended June 30, 2009, in order to maintain an effective tax rate consistent with the estimated annual rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Because this adjustment will vary each quarter, but will have no effect on net income for the year, management does not consider this adjustment to be representative of PEC’s fundamental core earnings. Additionally, management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEC’s fundamental core earnings. Accordingly, the impacts of tax levelization and the change in the tax treatment of the Medicare Part D subsidy are excluded in computing PEC’s Ongoing Earnings.

PROGRESS ENERGY FLORIDA

PEF contributed net income available to parent totaling $119 million for each of the three months ended June 30, 2010 and 2009. Net income available to parent for the three months ended June 30, 2010, compared to the same period in 2009, was increased by higher returns earned on nuclear and ECRC assets and increased retail base rates, offset by unfavorable AFUDC equity, lower wholesale base revenues and estimated Crystal River Unit No. 3 (CR3) joint owner replacement power costs in the current year. PEF contributed Ongoing Earnings of $119 million and $121 million for the three months ended June 30, 2010 and 2009, respectively. There were no 2010 Ongoing Earnings adjustments to net income available to parent. The 2009 Ongoing Earnings adjustment to net income available to parent was due to PEF recording a tax levelization charge of $2 million. Management does not consider this charge to be representative of PEF’s fundamental core earnings and excluded this charge in computing PEF’s Ongoing Earnings.

PEF contributed net income available to parent totaling $220 million and $207 million for the six months ended June 30, 2010 and 2009, respectively. The increase in net income available to parent for the six months ended June 30, 2010, compared to the same period in 2009, was primarily due to higher returns earned on nuclear and ECRC assets, increased retail base rates and the favorable impact of weather, partially offset by unfavorable AFUDC equity, lower wholesale base revenues, higher income tax expense due to the prior year benefit related to NDT funds and estimated CR3 joint owner replacement power costs in the current year. PEF contributed Ongoing Earnings of $232 million and $212 million for the six months ended June 30, 2010 and 2009, respectively. The 2010 Ongoing Earnings adjustments to net income available to parent were due to PEF recording a tax levelization charge of $2 million and a $10 million charge for the change in the tax treatment of the Medicare Part D subsidy. The 2009

Ongoing Earnings adjustment to net income available to parent was due to PEF recording a tax levelization charge of $5 million. Management does not consider these charges to be representative of PEF's fundamental core earnings and excluded these charges in computing PEF's Ongoing Earnings.

Three Months Ended June 30, 2010, Compared to Three Months Ended June 30, 2009

REVENUES

The revenue table that follows presents the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEF consider Base Revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and ECRC revenues. We and PEF have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, for the three months ended June 30 follows:

(in millions)

Customer Class	2010	Change	% Change	2009
Residential	$ 236	$ 26	12.4	$ 210
Commercial	88	7	8.6	81
Industrial	20	3	17.6	17
Governmental	23	3	15.0	20
Unbilled	28	(4)	-	32
Total retail base revenues	395	35	9.7	360
Wholesale base revenues	38	(14)	(26.9)	52
Total Base Revenues	433	21	5.1	412
Clause recoverable regulatory returns	42	29	223.1	13
Miscellaneous	53	7	15.2	46
Fuel and other pass-through revenues	724	(39)	-	763
Total operating revenues	$ 1,252	$ 18	1.5	$ 1,234

PEF's total Base Revenues were $433 million and $412 million for the three months ended June 30, 2010 and 2009, respectively. The $21 million increase in Base Revenues was due primarily to the $26 million impact of increased retail base rates from the repowered Bartow Plant (See Note 3B) and the $12 million favorable impact of weather, partially offset by $14 million lower wholesale base revenues and the $3 million unfavorable impact of net retail customer growth and usage. The favorable impact of weather was driven by 9 percent higher cooling degree days than 2009. Additionally, cooling degree days were 15 percent higher than normal. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 4,000 increase in the average number of customers for 2010 compared to 2009. PEF's wholesale base revenues were $38 million and $52 million for the three months ended June 30, 2010 and 2009, respectively. The $14 million decrease was due primarily to an amended contract with a major customer.

PEF's clause recoverable regulatory returns were $42 million and $13 million for the three months ended June 30, 2010 and 2009, respectively. The $29 million higher revenues primarily relate to higher returns on ECRC assets due to placing approximately $770 million of Clean Air Interstate Rule (CAIR) projects into service in late 2009. We anticipate this trend of higher returns to continue throughout 2010.

PEF’s miscellaneous revenues increased $7 million in 2010 primarily due to higher transmission revenues driven by favorable weather.

PEF's electric energy sales in kWh and the percentage change by customer class for the three months ended June 30 were as follows:

(in millions of kWh)

Customer Class	2010	Change	% Change	2009
Residential	4,598	90	2.0	4,508
Commercial	2,939	(9)	(0.3)	2,948
Industrial	867	35	4.2	832
Governmental	824	19	2.4	805
Unbilled	800	97	-	703
Total retail kWh sales	10,028	232	2.4	9,796
Wholesale	1,031	71	7.4	960
Total kWh sales	11,059	303	2.8	10,756

The increase in retail kWh sales in 2010 was primarily due to favorable weather as previously discussed. Despite the slight decrease in commercial kWh sales in 2010, commercial revenues increased primarily due to increased base rates.

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

The economic conditions and general housing downturn in the United States has continued to contribute to a slowdown in customer growth and usage in PEF's service territory. The impact of the general housing downturn was especially severe in several states, including Florida. Additionally, we believe the current economic conditions have impacted our wholesale customers' usage. We cannot predict how long these economic conditions may last or the extent to which revenues may be impacted. In the future, PEF's customer usage could be impacted by customer response to EE programs and to increased rates.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation and energy purchased in the market to meet customer load. Fuel and the majority 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 $607 million for the three months ended June 30, 2010, which represents a $36 million decrease compared to the same period in 2009. Fuel used in electric generation decreased $75 million to $368 million compared to the same period in 2009. This decrease was primarily due to lower deferred fuel expense of $101 million resulting from lower fuel rates that assumed the plant outage at CR3 would be completed within its original schedule (See "Other Matters – Nuclear"), partially offset by increased current year fuel costs of $27 million primarily due to higher system requirements driven by favorable weather. Purchased power expense increased $39 million to $239 million compared to the same period in 2009. This increase was primarily due to an increase in the recovery of deferred capacity costs of $28 million resulting from increased rates and increased purchases of $11 million primarily related to CR3 joint owner replacement power costs and increased capacity costs. In aggregate, fuel and purchased power expenses increased $13 million due to estimated CR3 joint owner replacement power costs based on PEF's current expected return to service (See Note 3B).

Operation and Maintenance

O&M expense was $208 million for the three months ended June 30, 2010, which represents a $4 million increase compared to the same period in 2009. O&M expense increased primarily due to the $16 million prior year pension deferral in accordance with an FPSC order, partially offset by $10 million favorable ECRC costs due to lower nitrogen oxides (NOx) allowances used resulting from a scrubber placed in service in December 2009. The ECRC expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In aggregate, O&M expenses recoverable through base rates increased $11 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $110 million for the three months ended June 30, 2010, which represents a $5 million increase compared to the same period in 2009. Depreciation, amortization and accretion expense increased primarily due to $14 million higher nuclear cost-recovery amortization, partially offset by a $10 million reduction in the cost of removal component of depreciation expense in accordance with the base rate settlement agreement (See Note 3B). The nuclear cost-recovery amortization is recovered through a cost-recovery clause and, therefore, has no material impact on earnings. In aggregate, depreciation, amortization and accretion expenses recoverable through base rates decreased $7 million compared to the same period in 2009.

Other

Other operating expenses of $7 million for the three months ended June 30, 2009, is primarily due to the regulatory disallowance of fuel costs (See Note 7C in the 2009 Form 10-K).

Total Other Income, Net

Total other income, net was $12 million for the three months ended June 30, 2010, which represents a $24 million decrease compared to the same period in 2009. This decrease was primarily due to $19 million unfavorable AFUDC equity and $5 million lower investment gains on certain employee benefit trusts resulting from financial market conditions. The unfavorable AFUDC equity is related to lower eligible construction project costs with the repowered Bartow Plant and CAIR projects being placed in service in the second and fourth quarters of 2009, respectively.

Total Interest Charges, Net

Total interest charges, net was $68 million for the three months ended June 30, 2010, which represents a $13 million increase compared to the same period in 2009. This increase was primarily due to $7 million unfavorable AFUDC debt related to lower eligible construction project costs as discussed above and $6 million higher interest driven by higher average long-term debt outstanding.

Income Tax Expense

Income tax expense increased $12 million for the three months ended June 30, 2010, compared to the same period in 2009, primarily due to the $8 million impact of the unfavorable AFUDC equity discussed above and the $4 million tax impact of higher pre-tax income, partially offset by the $2 million impact of tax levelization. AFUDC equity is excluded from the calculation of income tax expense. PEF’s income tax expense was increased by $2 million for the three months ended June 30, 2009, compared to no impact for the three months ended June 30, 2010 related to the impact of tax levelization. GAAP requires companies to apply a levelized effective income tax rate to interim periods that is consistent with the estimated annual effective tax rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Because this adjustment will vary each quarter, but will have no effect on net income for the year, management does not consider this adjustment to be representative of PEF’s fundamental core earnings. Therefore, the impact of tax levelization is excluded in computing PEF’s Ongoing Earnings.

Six Months Ended June 30, 2010, Compared to Six Months Ended June 30, 2009

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, for the six months ended June 30 follows:

(in millions)

Customer Class	2010	Change	% Change	2009
Residential	$ 497	$ 88	21.5	$ 409
Commercial	169	17	11.2	152
Industrial	38	4	11.8	34
Governmental	44	5	12.8	39
Unbilled	27	(3)	-	30
Total retail base revenues	775	111	16.7	664
Wholesale base revenues	81	(32)	(28.3)	113
Total Base Revenues	856	79	10.2	777
Clause recoverable regulatory returns	80	60	300.0	20
Miscellaneous	106	16	17.8	90
Fuel and other pass-through revenues	1,480	(129)	-	1,609
Total operating revenues	$ 2,522	$ 26	1.0	$ 2,496

PEF's total Base Revenues were $856 million and $777 million for the six months ended June 30, 2010 and 2009, respectively. The $79 million increase in Base Revenues was due primarily to the $59 million impact of increased retail base rates from the repowered Bartow Plant (See Note 3B), the $47 million favorable impact of weather, and the $5 million favorable impact of net retail customer growth and usage, partially offset by $32 million lower wholesale base revenues. The favorable impact of weather was driven by 74 percent higher heating degree days than 2009. Additionally, heating degree days were 128 percent higher than normal in 2010. The favorable impact of net retail customer growth and usage was driven by an increase in the average usage per retail customer and a net 1,000 increase in the average number of customers for 2010 compared to 2009. PEF's wholesale base revenues were $81 million and $113 million for the six months ended June 30, 2010 and 2009, respectively. The $32 million decrease was due primarily to an amended contract with a major customer and decreased revenues from a contract that expired in 2009. Given the current economic conditions, PEF does not believe it is likely to replace in 2010 wholesale contracts that expired in 2009.

PEF's clause recoverable regulatory returns were $80 million and $20 million for the six months ended June 30, 2010 and 2009, respectively. The $60 million higher revenues primarily relate to higher returns on ECRC assets due to placing approximately $770 million of CAIR projects into service in late 2009. We anticipate this trend of higher returns to continue throughout 2010.

PEF's miscellaneous revenues increased $16 million in 2010 primarily due to higher transmission revenues driven by favorable weather.

PEF's electric energy sales in kWh and the percentage change by customer class for the six months ended June 30 were as follows:

(in millions of kWh)

Customer Class	2010	Change	% Change	2009
Residential	9,724	929	10.6	8,795
Commercial	5,536	34	0.6	5,502
Industrial	1,635	12	0.7	1,623
Governmental	1,558	21	1.4	1,537
Unbilled	730	42	-	688
Total retail kWh sales	19,183	1,038	5.7	18,145
Wholesale	2,034	22	1.1	2,012
Total kWh sales	21,217	1,060	5.3	20,157

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

Wholesale kWh sales have increased primarily due to favorable weather, which resulted in increased deliveries under a certain capacity contract that has high demand and low energy charges. Despite the increase in sales, wholesale base revenues have decreased primarily due to a contract amendment and a contract that expired in 2009 as previously discussed.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power expenses were $1.233 billion for the six months ended June 30, 2010, which represents a $82 million decrease compared to the same period in 2009. Fuel used in electric generation decreased $174 million to $781 million compared to the same period in 2009. This decrease was primarily due to lower deferred fuel expense of $279 million resulting from lower fuel rates as previously discussed, partially offset by increased current year fuel costs of $105 million. The increase in current year fuel costs was primarily due to higher system requirements driven by favorable weather. Purchased power expense increased $92 million to $452 million compared to the same period in 2009. This increase was primarily due to an increase in the recovery of deferred capacity costs of $64 million resulting from increased rates and increased purchases of $29 million driven by increased capacity costs and estimated CR3 joint owner replacement power costs. In aggregate, fuel and purchased power expenses increased $19 million due to estimated CR3 joint owner replacement power costs, based on PEF's current expected return to service (See Note 3B).

Operation and Maintenance

O&M expense was $413 million for the six months ended June 30, 2010, which represents a $7 million increase compared to the same period in 2009. O&M expense increased primarily due to the $16 million prior year pension deferral in accordance with an FPSC order and higher Energy Conservation Cost Recovery Clause (ECCR) costs of $10 million driven by increased customer usage of load management programs and home improvement incentives, partially offset by $16 million favorable ECRC costs due to lower NOx allowances used resulting from a scrubber placed in service in December 2009 and lower pension expense of $4 million driven by revised actuarial estimates. The ECCR and ECRC expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In aggregate, O&M expenses recoverable through base rates increased $15 million compared to the same period in 2009.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $234 million for the six months ended June 30, 2010, which represents a $31 million decrease compared to the same period in 2009. Depreciation, amortization and accretion expense decreased primarily due to $29 million lower nuclear cost-recovery amortization, lower depreciation rate impact of $17 million and a reduction in the cost of removal component of depreciation expense of $10 million in accordance with the FPSC base rate settlement, partially offset by $29 million impact of depreciable asset base increases. The nuclear cost-recovery amortization is recovered through a cost-recovery clause and, therefore, has no material impact on earnings. The lower depreciation rate resulted from a depreciation study in conjunction with the 2009 base rate case. In aggregate, depreciation, amortization and accretion expenses recoverable through base rates decreased $4 million compared to the same period in 2009.

Taxes Other Than on Income

Taxes other than on income was $176 million for the six months ended June 30, 2010, which represents a $8 million increase compared to the same period in 2009. This increase was primarily due to higher property taxes of $7 million resulting primarily from placing the repowered Bartow Plant in service in June 2009.

Other

Other operating expenses of $7 million for the six months ended June 30, 2009, is primarily due to the regulatory disallowance of fuel costs (See Note 7C in the 2009 Form 10-K).

Total Other Income, Net

Total other income, net was $22 million for the six months ended June 30, 2010, which represents a $45 million decrease compared to the same period in 2009. This decrease was primarily due to $41 million unfavorable AFUDC equity related to lower eligible construction project costs with the repowered Bartow Plant and CAIR projects being placed in service in the second and fourth quarters of 2009, respectively.

Total Interest Charges, Net

Total interest charges, net was $127 million for the six months ended June 30, 2010, which represents a $14 million increase compared to the same period in 2009. This increase was primarily due to $11 million unfavorable AFUDC debt related to lower eligible construction project costs as discussed above.

Income Tax Expense

Income tax expense increased $59 million for the six months ended June 30, 2010, compared to the same period in 2009, primarily due to the $27 million tax impact of higher pre-tax income, the $16 million impact of the unfavorable AFUDC equity discussed above, the $11 million impact of the favorable prior year tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT to the qualified NDT and the $10 million impact of the change in the tax treatment of the Medicare Part D subsidy resulting from recently enacted federal health care reform (See Note 8). AFUDC equity is excluded from the calculation of income tax expense. PEF's income tax expense was increased by $2 million and $5 million for the six months ended June 30, 2010, and 2009, respectively, related to the impact of tax levelization. Because this adjustment will vary each quarter, but will have no effect on net income for the year, management does not consider this adjustment to be representative of PEF's fundamental core earnings. Additionally, management does not consider the change in the tax treatment of the Medicare Part D subsidy to be representative of PEF's fundamental core earnings. Accordingly, the impacts of tax levelization and the change in the tax treatment of the Medicare Part D subsidy are excluded in computing PEF's Ongoing Earnings.

CORPORATE AND OTHER

The Corporate and Other segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. A discussion of the items excluded from Corporate and Other's Ongoing Earnings is included in the detailed discussion and analysis below. Management believes the excluded items are not representative of our fundamental core earnings. The following table reconciles Corporate and Other's Ongoing Earnings to GAAP net income attributable to controlling interests:

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2010	2009	2010	2009
Other interest expense	$ (77)	$ (64)	$ (153)	$ (119)
Other income tax benefit	27	28	51	38
Other income	-	2	5	9
Ongoing Earnings	(50)	(34)	(97)	(72)
Tax levelization	-	(4)	(2)	(6)
CVO mark-to-market	-	1	-	8
Impairment, net of tax	-	(2)	-	(2)
Discontinued operations attributable to controlling interests, net of tax	(1)	(1)	-	(1)
Net loss attributable to controlling interests	$ (51)	$ (40)	$ (99)	$ (73)

OTHER INTEREST EXPENSE

Other interest expense increased $13 million and $34 million for the three and six months ended June 30, 2010, compared to the same period in 2009, primarily due to higher average debt outstanding.

OTHER INCOME TAX BENEFIT

Other income tax benefit increased $13 million for the six months ended June 30, 2010, compared to the same period in 2009, primarily due to the $15 million favorable tax impact of higher pre-tax loss.

ONGOING EARNINGS ADJUSTMENTS

Tax Levelization

GAAP requires companies to apply a levelized effective income tax rate to interim periods that is consistent with the estimated annual effective tax rate. Income tax expense was increased by $4 million for the three months ended June 30, 2009 compared to no impact for the same period in 2010, and was increased by $2 million and $6 million for the six months ended June 30, 2010 and 2009, respectively, in order to maintain an effective tax rate consistent with the estimated annual rate. Fluctuations in estimated annual earnings and the timing of various permanent items of income or deduction can cause fluctuations in the effective tax rate for interim periods. Because this adjustment will vary each quarter, but will have no effect on net income for the year, management does not consider this adjustment to be representative of our fundamental core earnings.

CVO Mark-to-Market

At June 30, 2010 and 2009, the contingent value obligations (CVOs) had fair values of approximately $15 million and $26 million, respectively. Progress Energy recorded an unrealized gain of $1 million for the three months ended June

30, 2009, to record the changes in fair value of the CVOs, which had average unit prices of $0.16 and $0.27 at June 30, 2010 and 2009, respectively. There was no change in the fair value of the CVOs for the three months ended June 30, 2010. Progress Energy recorded an unrealized gain of $8 million for the six months ended June 30, 2009, to record the changes in fair value of the CVOs. There was no change in the fair value of the CVOs for the six months ended June 30, 2010. See Note 15 in the 2009 Form 10-K for further information. Because Progress Energy is unable to predict the changes in the fair value of the CVOs, management does not consider this adjustment to be representative of our fundamental core earnings.

Impairment, Net of Tax

We recorded a $2 million impairment of certain miscellaneous investments during the three and six months ended June 30, 2009.

Discontinued Operations Attributable to Controlling Interests, Net of Tax

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. We recognized $1 million of loss from discontinued operations attributable to controlling interests, net of tax, for the three months ended June 30, 2010 and 2009, and for the six months ended June 30, 2009.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Our significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, substantially all of which is generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity. As discussed in "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized.

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

As a registered holding company, our establishment of intercompany extensions of credit is subject to regulation by the Federal Energy Regulatory Commission (FERC) under regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005). Our subsidiaries participate in internal money pools, administered by PESC, to more effectively utilize cash resources and reduce external short-term borrowings. The utility money pool allows the Utilities to lend to and borrow from each other. A non-utility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and non-utility money pools but cannot borrow funds.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.2 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures. During 2009, PEC paid a dividend of $200 million to the Parent and PEF received equity contributions of $620 million from the Parent. During the six months ended June 30, 2010, PEC and PEF each paid dividends of $50 million to the Parent. There are a number of factors that impact the Utilities’ decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, and/or ongoing sales of common stock from our Progress Energy Investor Plus Plan (IPP) are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2010. For the fiscal year 2010, we plan, subject to market conditions, to realize up to $500 million from the sale of stock through ongoing equity sales, of which $405 million has been realized through June 30, 2010 (See "Financing Activities").

We have 16 financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as back-ups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At June 30, 2010, the Parent had no outstanding borrowings under its credit facility, no outstanding commercial paper and had issued $38 million of letters of credit, which were supported by the revolving credit facility. At June 30, 2010, PEC and PEF had no outstanding borrowings under their respective credit facilities and no outstanding commercial paper. Based on these outstanding amounts at June 30, 2010, there was a combined $1.992 billion available for additional borrowings.

At June 30, 2010, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At June 30, 2010, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 9A for additional information with regard to our commodity derivatives.

At June 30, 2010, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At June 30, 2010, the sum of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps were each in a net mark-to-market liability position. See Note 9B for additional information with regard to our interest rate derivatives.

On July 21, 2010, the Wall Street Reform and Consumer Protection Act (H.R. 4173) was signed into law. Among other things, the law includes provisions related to the swaps and over-the-counter derivatives markets. Under the law, we expect to be exempt from mandatory clearing and exchange trading requirements for our commodity and interest rate hedges because we are an end user of these products. Capital and margin requirements for these hedges are expected to be determined over the next year as more detailed rules and regulations are published. At this time, we do not expect the law to have a material impact on our financial condition. However, we cannot determine the impact until the final regulations are issued.

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

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. We will continue to monitor the credit markets to maintain an appropriate level of liquidity. Our ability to access the capital markets on favorable terms may be negatively impacted by credit rating actions. Risk factors associated with the capital markets and credit ratings are discussed below and in Item 1A, "Risk Factors" to the 2009 Form 10-K.

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

HISTORICAL FOR 2010 AS COMPARED TO 2009

CASH FLOWS FROM OPERATIONS

Net cash provided by operating activities increased $64 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The increase was primarily due to $205 million lower cash used for inventory, primarily due to a change in generation mix and higher coal consumption as a result of favorable weather that was fulfilled through 2010 usage of inventory from year-end 2009; and $140 million increase from accounts payable, primarily driven by the timing of payments to vendors for increased purchases of fuel and purchased power resulting from outages and favorable weather. These impacts were partially offset by a $266 million decrease from the recovery of deferred fuel costs primarily as a result of lower fuel rates and higher current year fuel expenses.

INVESTING ACTIVITIES

Net cash used by investing activities decreased by $13 million for the six months ended June 30, 2010, when compared to the same period in the prior year. This decrease was primarily due to $227 million lower capital expenditures at PEF primarily related to environmental compliance and nuclear projects and $15 million insurance proceeds from the CR3 delamination project, partially offset by $178 million higher capital expenditures at PEC primarily related to the Wayne County, Richmond County and Sutton generation sites and $59 million increase in nuclear fuel additions primarily related to PEC’s one additional refueling outage for 2010 compared to 2009.

FINANCING ACTIVITIES

Net cash provided by financing activities decreased by $384 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The decrease was primarily due to a $746 million decrease in proceeds from long-term debt issuances, net primarily due to PEF’s $591 million proceeds from long-term debt issuances in 2010 compared to $1.337 billion proceeds from long-term debt issuances at the Parent and PEC in 2009; and a $140 million decrease in net issuance of common stock, primarily related to the Parent’s January 2009 common stock offering. These impacts were partially offset by a $510 million decrease in repayments of short-term debt driven by commercial paper repayments in 2009. A discussion of our 2010 financing activities follows.

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

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

At December 31, 2009, we had 500 million shares of common stock authorized under our charter, of which 281 million shares were outstanding. For the three and six months ended June 30, 2010, respectively, we issued approximately 5.4 million and 11.5 million shares of common stock through the IPP and equity incentive plans resulting in approximately $208 million and $405 million in net proceeds. For the three months ended June 30, 2009, we issued an immaterial number of shares of common stock. For the six months ended June 30, 2009, we issued approximately 15.5 million shares of common stock resulting in approximately $545 million in net proceeds. Included in these amounts were 14.4 million shares issued in an underwritten public offering for net proceeds of approximately $523 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

The Utilities produce substantially all of our consolidated cash from operations. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At June 30, 2010, we have carried forward $806 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

We expect to be able to meet our future liquidity needs through cash from operations, commercial paper issuance, availability under our credit facilities, long-term debt financings and equity offerings, including periodic ongoing sales of common stock from our IPP and employee benefit and stock option plans.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customer's future energy needs (See Item 1A, "Risk Factors" to 2009 Form 10-K).

We issue commercial paper to meet short-term liquidity needs. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our revolving credit agreements (RCAs), issuing short-term notes, issuing long-term debt and/or issuing equity. There was an immaterial increase in PEF's RCA facility fees as a result of the downgrade of PEF's senior unsecured credit rating by Moody's Investors Service, Inc. (Moody's) on April 9, 2010.

The current RCAs for the Parent, PEC and PEF expire in May 2012, June 2011 and March 2011, respectively. We expect to enter new credit facilities prior to the respective expirations of our current RCAs. In the event we enter into new credit facilities, we cannot predict the terms, prices, durations or participants in such facilities.

Progress Energy and its subsidiaries have approximately $12.641 billion in outstanding long-term debt, including the $705 million current portion. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may lower our tax-exempt bond ratings. In the event of a one notch downgrade of PEC's and/or PEF's senior secured debt rating by S&P, the ratings of such utility's tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a one notch downgrade by Moody's, PEC's and PEF's tax-exempt bonds will continue to be rated at or above A3. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $129 million of contributions directly to pension plan assets in 2010 (See Note 8).

As discussed in "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under "Other Matters – Energy Demand" will require the Utilities to make significant capital investments. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and/or common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation. As discussed in "Other Matters –

Nuclear – Potential New Construction,” PEF expects its capital expenditures for the proposed nuclear plant in Levy County, Fla. (Levy) will be significantly less in the near term than previously planned in light of schedule shifts and other factors.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2009, have impacted the amount of collateral posted with counterparties. At June 30, 2010, we had posted approximately $194 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2010 and 2011. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. As discussed in Note 9C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

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

At June 30, 2010, the current portion of our long-term debt was $705 million. We expect to fund the Parent's $700 million March 2011 long-term debt maturity with proceeds from long-term debt issuances, including a portion of the remaining proceeds from the Parent's November 2009 $950 million long-term debt issuance.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 3 and "Other Matters – Regulatory Environment," and filings for recovery of environmental costs, as discussed in Note 12 and in "Other Matters – Environmental Matters," may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources. Regulatory developments expected to have a material impact on our liquidity are discussed below.

As discussed further in Note 3 and in "Other Matters – Regulatory Environment," the North Carolina, South Carolina and Florida legislatures passed energy legislation that became law in recent years. These laws may impact our liquidity over the long term, including among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and EE.

PEC Cost-Recovery Clause

On June 23, 2010, the SCPSC approved PEC's request for a decrease in the fuel rate charged to its South Carolina ratepayers. The $17 million decrease effective July 1, 2010, is driven by declining fuel prices.

On June 4, 2010, PEC filed with the NCUC for a decrease in the fuel rate charged to its North Carolina ratepayers. If approved, the $170 million decrease would be effective December 1, 2010. This decrease is also driven by declining fuel prices.

On June 4, 2010, PEC filed with the NCUC for an increase in the DSM and EE rate charges to its North Carolina ratepayers. If approved, the $31 million increase would be effective December 1, 2010. We cannot predict the outcome of this matter.

PEC Other Matters

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

On October 22, 2009, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility will be in service by January 2013.

On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC intends to continue to depreciate these units using the current depreciation rates on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study.

On June 9, 2010, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. to replace the existing coal-fired generation at this site. PEC projects that the generating facility would be in service by late 2013 or early 2014.

PEF Base Rates

On January 11, 2010, the FPSC approved a base rate increase for PEF of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. The FPSC authorized PEF the opportunity to earn a return on equity (ROE) of 10.5 percent. Subsequently, PEF filed petitions for a motion for reconsideration and approval of an accounting order with the FPSC.

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case and to an accounting order petition filed by PEF in 2010. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order and its accounting order petition. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. The settlement agreement also provides that PEF will have the discretion to reduce depreciation expense (cost of removal component) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in the cost of removal component of the depreciation reserve in 2012 until the earlier of (a) PEF's applicable cost of removal reserve reaches zero, or (b) the expiration of the settlement agreement at the end of 2012. In the event PEF reduces depreciation expense by less than the annual amounts for 2010 or 2011, PEF may carry forward (i.e., increase the annual cap by) any unused cost of removal reserve amounts in subsequent years during the term of the agreement. The balance of the cost of removal reserve is impacted by accruals in accordance with PEF's latest depreciation study, removal costs expended and reductions in depreciation expense as permitted by the settlement agreement. For the three and six months ended June 30, 2010, PEF recognized a $10 million reduction in depreciation expense pursuant to the settlement agreement. PEF's applicable cost of removal reserve of $516 million is recorded as a regulatory liability on its June 30, 2010 Balance Sheet. The settlement agreement also provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited, or interim base rate relief, or any combination thereof. Prior to requesting any such relief, PEF must have reflected on its referenced surveillance report associated depreciation expense reductions of at least $150 million. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost-recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the legislature or FPSC determines are clause recoverable, or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. PEF also may, at its discretion, accelerate in whole or in part the amortization of certain regulatory assets over the term of the settlement agreement. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period PEF can begin recovery, subject to refund, of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC.

Nuclear Cost Recovery

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

In 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consisted of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. The FPSC approved the alternate proposal allowing PEF to recover revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of $198 million of capacity revenues and the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

On April 30, 2010, PEF filed its annual nuclear cost-recovery filing with the FPSC to recover $164 million which includes recovery of pre-construction, carrying and CCRC recoverable O&M costs incurred or anticipated to be incurred during 2011, recovery of $60 million of the 2009 deferral in 2011, as well as the estimated actual true-up of 2010 costs associated with the Levy and CR3 uprate projects. This results in an estimated decrease in the nuclear cost-recovery charge of $1.46 per 1,000 kWh for residential customers, which if approved, would begin with the first January 2011 billing cycle. The FPSC has scheduled hearings in this matter for August 24-27, 2010, with a decision expected in October 2010. We cannot predict the outcome of this matter.

Demand-Side Management Cost Recovery

On December 30, 2009, the FPSC ordered PEF and other Florida utilities to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. Under the order, PEF's aggregate conservation goals over the next ten years were: 1,183 Summer MW, 1,072 Winter MW, and 3,488 gigawatt-hours (GWh) in the aggregate. PEF filed with the FPSC a motion for reconsideration to correct what we believed were oversights or errors. The FPSC subsequently revised the aggregate goals to 1,134 Summer MW, 1,058 Winter MW, and 3,205 GWh over the next ten years. On March 30, 2010, PEF filed a petition for approval of its proposed DSM plan and to authorize cost recovery through the Energy Conservation Cost Recovery Clause (ECCR). The estimated average annual program costs are approximately $484 million, which corresponds to an average annual residential customer electric bill impact of approximately $17 per 1,200 kWh. An agenda conference has been scheduled by the FPSC for August 31, 2010. We cannot predict the outcome of this matter.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

GUARANTEES

At June 30, 2010, our guarantees have not changed materially from what was reported in the 2009 Form 10-K.

MARKET RISK AND DERIVATIVES

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 9 and Item 3, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

As part of our ordinary course of business, we and the Utilities enter into various long- and short-term contracts for fuel requirements at our generating plants. Significant changes from the commitment amounts reported in Note 22A in the 2009 Form 10-K can result from new contracts, changes in existing contracts along with the impact of fluctuations in current estimates of future market prices for those contracts that are market price indexed. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels, and other financial commitments. Additional commitments for fuel and related transportation will be required to supply the Utilities' future needs. At June 30, 2010, our and the Utilities' contractual cash obligations and other commercial commitments have not changed materially from what was reported in the 2009 Form 10-K except as discussed below.

PEC

In April 2010, PEC entered into a conditional agreement for firm pipeline transportation capacity to support PEC's gas supply needs for the approximate period of June 2013 through May 2033. The total cost to PEC associated with this agreement is estimated to be approximately $477 million. The agreement is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of this agreement, the estimated costs are not currently considered a fuel commitment of PEC.

PEF

PEF's construction obligations included in Note 22A to the 2009 Form 10-K, which were primarily comprised of contractual obligations related to the Levy Engineering, Procurement, and Construction (EPC) agreement, totaled $1.455 billion, $2.981 billion, $2.818 billion and $1.543 billion, respectively, for less than one year, one to three years, three to five years and more than five years from December 31, 2009. As disclosed in "Other Matters – Nuclear – Potential New Construction", we executed an amendment to the Levy EPC agreement in 2010 because of the schedule shifts and will postpone major construction activities on the project until after the NRC issues the combined license (COL), which is expected to be in late 2012 if the licensing schedule remains on track. Therefore, we will defer substantially all expenditures under the EPC agreement until the COL is received. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict the timing of when those obligations will be satisfied or the magnitude of any change. Additionally, in light of the schedule shifts in the Levy project, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work will be suspended on the remaining long lead time equipment items and PEF will be in suspension negotiations with the selected equipment vendors in the coming months. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. We cannot predict the outcome of this matter.

On June 30, 2010, PEF entered into a long-term service agreement for the Hines Energy Complex covering scheduled maintenance events through 2029. The total cost to PEF associated with this agreement is estimated to be approximately $390 million over the term of the agreement.

OTHER MATTERS

GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. The carrying amounts of goodwill at June 30, 2010 and December 31, 2009, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. We perform our annual impairment tests as of April 1 each year. During the second quarter of 2010, we completed the required 2010 annual tests, which indicated the goodwill was not impaired. If the fair values of PEC and PEF had been lower by 10 percent, there still would be no impact on the reported value of their goodwill.

We calculate the fair value of our utility segments by considering various factors, including valuation studies based primarily on income and market approaches. More emphasis is applied to the income approach as substantially all of the utility segments' cash flows are from rate-regulated operations. In such environments, revenue requirements are adjusted periodically by regulators based on factors including levels of costs, sales volumes and costs of capital. Accordingly, the utility segments operate to some degree with a buffer from the direct effects, positive or negative, of significant swings in market or economic conditions.

The income approach uses discounted cash flow analyses to determine the fair value of the utility segments. The estimated future cash flows from operations are based on the utility segments' business plans, which reflect management's assumptions related to customer usage based on internal data and economic data obtained from third-party sources. The business plans assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also determines the appropriate discount rate for the utility segments based on the weighted average cost of capital for each utility, which takes into account both the cost of equity and pre-tax cost of debt. As each utility segment has a different risk profile based on the nature of its operations, the discount rate for each reporting unit may differ.

The market approach uses implied market multiples derived from comparable peer utilities and market transactions to estimate the fair value of the utility segments. Peer utilities are evaluated based on percentage of revenues generated by regulated utility operations; percentage of revenues generated by electric operations; generation mix, including coal, gas, nuclear and other resources; market capitalization as of the valuation date; and geographic location. Comparable market transactions are evaluated based on the availability of financial transaction data and the nature and geographic location of the businesses or assets acquired, including whether the target company had a significant electric component. The selection of comparable peer utilities and market transactions, as well as the appropriate multiples from within a reasonable range, is a matter of professional judgment.

The calculations in both the income and market approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility segments could be significantly different in future periods, which could result in a future impairment charge to goodwill.

As an overall test of the reasonableness of the estimated fair values of the utility segments, we compared their combined fair value estimate to Progress Energy's market capitalization as of April 1, 2010. The analysis confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

We monitor for events or circumstances, including financial market conditions and economic factors, that may indicate an interim goodwill impairment test is necessary. We would perform an interim impairment test should any events occur or circumstances change that would more likely than not reduce the fair value of a utility segment below its carrying value.

REGULATORY ENVIRONMENT

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

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

Current retail rate matters affected by state regulatory authorities are discussed in Notes 3A and 3B. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency and renewable energy, including $3.4 billion in Smart Grid technology development grants, $615 million for Smart Grid storage, monitoring and technology viability, $6.3 billion for energy efficiency and conservation grants and $2 billion in tax credits for the purchase of plug-in electric vehicles. On April 28, 2010, we accepted a grant from the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds. In addition to providing the Utilities real-time information about the state of their electric grids, the smart grid transition will enable customers to better understand and manage their energy use, and will provide for more efficient integration of renewable energy resources. PEC and PEF each will receive up to $100 million over a three-year period as project work progresses. Supplementing the DOE grant, the Utilities will invest more than $300 million in Smart Grid projects, which include enhancements to distribution equipment, installation of 160,000 additional smart meters and additional public infrastructure for plug-in electric vehicles. Projects funded by the grant must be completed by April 2013.

We have incurred $60 million of allowable Smart Grid grant project costs through June 30, 2010. As of June 30, 2010, the reimbursable portion of these project costs are reflected in receivables, net and other current liabilities on the Consolidated Balance Sheets. On July 23, 2010, we submitted to the DOE our initial request for reimbursement of $30 million, which represents 50 percent of allowable Smart Grid project costs incurred.

On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce greenhouse gas (GHG) emissions as well as a national renewable energy portfolio standard (REPS). The bill also calls for investment in the electric grid, more production and utilization of electric vehicles and improvements in energy efficiency in buildings and appliances. The full impact of the legislation, if enacted into law, cannot be determined at this time and will depend upon changes made to its provisions during the legislative process and the manner in which key provisions are implemented, including the regulation of carbon. The U.S. Senate is considering similar proposals. The full impact of final legislation, if enacted, and additional regulation resulting from these and other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery. Also, the Obama administration has announced a goal of encouraging investment in transmission and promoting renewable resources while also pricing GHG emissions and setting a federal requirement for renewable energy.

The North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) requires PEC to file an annual compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, are participating in the REC tracking system, which came online July 1, 2010.

Florida energy law enacted in 2008 includes provisions that would, among other things, (1) help enhance the ability to cost-effectively site transmission lines; (2) require the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification in 2009; (3) direct the Florida Department of Environmental Protection (FDEP) to develop rules establishing a cap-and-trade program to regulate GHG emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification by the legislature; and (4) establish a new Florida Energy and Climate Commission as the principal governmental body to develop energy and climate policy for the state and to make recommendations to the governor and legislature on energy and climate issues. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until these agency actions are finalized, we cannot predict the costs of complying with the law.

In 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders include adoption of a maximum allowable emissions level of GHGs for Florida utilities, which will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions. Rulemaking is expected to continue through 2010, and the rule requires legislative ratification before implementation.

The executive orders also requested that the FPSC initiate a rulemaking that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida’s power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from onsite renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). In 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020 and provided the draft standard rule to the Florida legislature. The legislature did not take action on the matter in the 2009 and 2010 sessions. We cannot predict the outcome of this matter.

We cannot predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in “Energy Demand,” includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

ENERGY DEMAND

Implementing state and federal energy policies, promoting environmental stewardship and providing reliable electricity to meet the anticipated long-term growth within the Utilities’ service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our DSM and EE programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

We are actively pursuing expansion of our DSM and EE programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. Our previously discussed Smart Grid projects will aid in these initiatives. EE programs include any equipment, physical or program change that results in less energy used to perform the same function. We provide our residential customers with home energy audits and offer EE programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet Web site with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative energy projects to pursue the generation of electricity from swine waste and other plant or animal sources, biomass, solar, hydrogen, and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 250 MW of electricity generated from biomass and up to 60 MW of electricity generated from municipal solid waste sources. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 10 MW of electricity generated from solar photovoltaic generation as part of the NC REPS. Approximately half of these projects are online and the remainder should be online by the end of 2010. Additionally, customers across our service territory have connected approximately 4 MW of solar photovoltaic energy systems to our grid. In June 2009, we expanded our solar energy strategy to include a range of new solar incentives and programs, which are expected to increase our use of solar energy by more than 100 MW over the next decade.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants. In the near term, we will focus our efforts on modernizing the power system and pursuing other elements of a balanced portfolio while looking to new nuclear capacity as a critical part of the long-term mix.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The coal-fired units will be retired by the end of 2017. PEC has received approval from the NCUC for construction of a 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has also received approval from the NCUC to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C. to replace the existing coal-fired generation at this site. The facility is projected to be placed in service in late 2013 or early 2014. After 2017, PEC will continue to operate its Roxboro, Mayo and Asheville coal-fired plants in North Carolina, which have state-of-the-art emission controls. Emissions of NOx, sulfur dioxide (SO2), mercury and other pollutants have been reduced significantly at these sites.

As authorized under the Energy Policy Act of 2005 (EPACT), on October 4, 2007, the DOE published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects.

In 2008, Congress authorized $38.5 billion in loan guarantee authority for innovative energy projects. Of the total provided, $18.5 billion is set aside for nuclear power facilities, $2 billion for advanced nuclear facilities for the "front-end" of the nuclear fuel cycle, $10 billion for renewable and/or energy-efficient systems and manufacturing and distributed energy generation/transmission and distribution, $6 billion for coal-based power generation and industrial gasification at retrofitted and new facilities that incorporate carbon capture and sequestration or other beneficial uses of carbon, and $2 billion for advanced coal gasification. In June 2008, the DOE announced solicitations for a total of up to $30.5 billion of the amount authorized by Congress in federal loan guarantees for projects that employ advanced energy technologies that avoid, reduce or sequester air pollutants or greenhouse gas emissions and advanced nuclear facilities for the “front-end” of the nuclear fuel cycle.

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

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

NUCLEAR

Nuclear generating units are regulated by the NRC. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

In September 2009, CR3 began an outage for normal refueling and maintenance as well as its uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure, which has resulted in an extension of the outage. After a comprehensive analysis, PEF has determined that the concrete delamination at CR3 was caused by redistribution of stresses on the containment wall that occurred when we created an opening to accommodate the replacement of the unit’s steam generators. We are pursuing a detailed repair plan that would achieve the unit’s return to service during the fourth quarter of 2010. The actual return to service date will be determined by a number of factors, including regulatory reviews with the NRC and other agencies as appropriate, emergent work, final engineering designs and testing, weather and other developments. (See Note 3B.)

The NRC operating licenses for PEC’s nuclear units are currently operating under renewed licenses that expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF’s application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, if approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida. The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on the potential construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

In 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF’s application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs.

In 2008, the FPSC issued a final order granting PEF's Petition for a Determination of Need for Levy. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. In 2009, the Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy site certification that addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors, which was docketed, or accepted for review by the NRC on October 6, 2008. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On April 20-21, 2009, the Atomic Safety Licensing Board (ASLB) heard oral arguments on whether any of the joint interveners' proposed contentions will be admitted in the Levy COL proceeding. On July 8, 2009, the ASLB issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the potential safety and environmental impact of storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. In April 2010, the ASLB dismissed the contention regarding the safety of storage of low-level radioactive waste; however, interveners have resubmitted their contention regarding the potential safety of storage of low-level waste, which is being considered by the ASLB. PEF's appeal of the ASLB's 2009 decision was denied and a hearing on the remaining contentions will be conducted in 2012. Other COL applicants have received similar petitions raising similar potential contentions. We cannot predict the outcome of this matter.

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

As disclosed in PEF's 2010 nuclear cost-recovery filing discussed below, the schedule shifts will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates. PEF will postpone major construction activities on the project until after the NRC issues the COL, which is expected to be in late 2012 if the current licensing schedule remains on track. The schedule shifts will also allow more time for certainty around federal climate change policy, which is currently being debated. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. Taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification, we consider Levy to be PEF's preferred baseload generation option. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, public, regulatory and political support; adequate financial cost-recovery mechanisms; adequate levels of joint owner participation; customer rate impacts; project feasibility, including comparison to other generation options, DSM and EE programs; and availability and terms of capital financing. If the licensing schedule remains on track and if the decision to build is made, the first of the two proposed units could be in service in 2021. The second unit could be in service 18 months later.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts previously discussed. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF may incur fees and charges related to the disposition of outstanding purchase orders on long lead time equipment for the Levy nuclear project, which could be material. In June 2010, PEF completed its long lead time equipment disposition analysis to minimize the impact associated with the schedule shift. As a result of the analysis, PEF will continue with selected components of the long lead time equipment. Work will be suspended on the remaining long lead time equipment items and PEF will be in suspension negotiations with the selected equipment vendors in the coming months. In its April 30, 2010 nuclear cost-recovery filing, PEF included for rate-making purposes a point estimate of potential Levy disposition fees and charges of $50 million, subject to true-up. However, the amount of disposition fees and charges, if any, cannot be determined until suspension negotiations are completed. We cannot predict the outcome of this matter.

The total escalated cost for the two generating units was estimated in PEF’s petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate included land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. PEF’s 2010 nuclear cost-recovery filing included an updated analysis that demonstrated continued feasibility of the Levy project with PEF’s current estimated range of total escalated cost, including transmission, of $17.2 billion to $22.5 billion. The filed estimated cost range primarily reflects cost escalation resulting from the schedule shifts. There are many factors that will affect the total cost of the project and once PEF receives the COL, it will further refine the project timeline and budget. As previously discussed, we continue to evaluate the Levy project on an ongoing basis.

Florida regulations allow investor-owned utilities such as PEF to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balance of a nuclear power plant prior to commercial operation. The costs are recovered on an annual basis through the CCRC. Such amounts will not be included in a utility’s rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility.

In 2008, PEF sought and received approval from the FPSC to recover Levy preconstruction and carrying charges of $357 million as well as site selection costs of $38 million through the 2009 CCRC. In 2009, PEF received approval to defer until 2010 the recovery of $198 million of these costs. On October 16, 2009, the FPSC approved the recovery of $201 million of preconstruction costs, carrying costs and incremental O&M incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with Levy as part of the total $207 million FPSC-approved recovery of nuclear costs through the 2010 CCRC (See Note 3B). On April 30, 2010, PEF filed its annual nuclear cost-recovery filing with the FPSC to recover $164 million which includes recovery of pre-construction, carrying and CCRC recoverable O&M costs incurred or anticipated to be incurred during 2011, recovery of $60 million of the 2009 deferral in 2011, as well as the estimated actual true-up of 2010 costs associated with the Levy and CR3 uprate projects. This results in a decrease in the nuclear cost-recovery charge of $1.46 per 1,000 kWh for residential customers, which if approved, would begin with the first January 2011 billing cycle. The FPSC has scheduled hearings in this matter for August 24-27, 2010, with a decision expected in October 2010. We cannot predict the outcome of this matter.

In 2006, we announced that PEC selected a site at the Shearon Harris Nuclear Plant (Harris) to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris, which the NRC docketed on April 17, 2008. No petitions to intervene have been admitted in the Harris COL application. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019 (See "Energy Demand" above).

PEC's jurisdictions also have laws encouraging nuclear baseload generation. South Carolina law includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. North Carolina law authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and inclusion of construction work in progress in rate base with corresponding rate adjustment in a general rate case while a baseload generating plant is under construction.

SPENT NUCLEAR FUEL MATTERS

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. We have a contract with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nev. The Obama administration has determined that Yucca Mountain, Nev., is not a workable option for a nuclear waste repository and will discontinue its program to construct a repository at this site in 2010. The administration will continue to explore alternatives. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or spent nuclear fuel reprocessing. We cannot predict the outcome of this matter.

The NRC has proposed revisions to its waste confidence findings that would remove the provisions stating that the NRC's confidence in waste management, underlying the licensing of reactors, is based in part on a permanent repository being in operation by 2025. Instead, the NRC states that repository capacity will be available within 50 to 60 years beyond the licensed operation of all reactors, and that used fuel generated in any reactor can be safely stored on site without significant environmental impact for at least 60 years beyond the licensed operation of the reactor. We cannot predict the outcome of this matter.

On September 15, 2009, the NRC proposed licensing requirements for storage of spent nuclear fuel, which would clarify the term limits for specific licenses for independent spent fuel storage installations and for certificates of compliance for spent nuclear fuel storage casks. The agency proposal would formalize the site-by-site exemption the NRC has used for renewal applications requesting more than the current 20-year duration. The initial and renewal terms of a specific installation license would be effective for a period of up to 40 years. Similarly, the proposed rule would allow applicants for certificates of compliance to request initial and renewal terms of up to 40 years, provided they can demonstrate that all design requirements are satisfied for the requested term. We cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation and/or expansion of on-site dry cask storage facilities at PEC's Robinson Nuclear Plant (Robinson), PEC's Brunswick Nuclear Plant (Brunswick) and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated by their respective systems through the expiration of the operating licenses, including any license renewals, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license.

See Note 13C for information about the complaint filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open the Yucca Mountain or other facility would leave the DOE open to further claims by utilities.

ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 3 and 12). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 12A.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated. 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.

In June 2009, the EPA evaluated information about ash impoundment dams nationwide and posted a listing of 44 utility ash impoundment dams that are considered to have “high hazard potential,” including two of PEC’s ash impoundment dams. A “high hazard potential” rating is not related to the stability of those ash ponds but to the potential for harm should the impoundment dam fail. All of the dams at PEC’s coal ash ponds have been subject to periodic third-party inspection for many years in accordance with prior applicable requirements. In September 2009, the EPA rated the 44 “high hazard potential” impoundments, as well as other impoundments, from “unsatisfactory” to “satisfactory” based on their structural integrity and associated documentation.

Only dams rated as “unsatisfactory” would be considered to pose an immediate safety threat, but none of the facilities received an “unsatisfactory” rating. In total, six of PEC’s ash pond dams, including one “high hazard potential” impoundment, were rated as “poor” based on the contract inspector’s desire to see additional documentation and their evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the EPA’s recommendations for the active ponds and other recommended actions are under way. One ash pond dam has been determined by engineers to need modifications to comply with current standards for an extra margin of safety for slope stability. Design and permitting efforts for that work have been initiated. PEC is working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

As of January 1, 2010, dams at utility fossil-fired power plants in North Carolina, including dams for ash ponds, are subject to the North Carolina Dam Safety Act's applicable provisions, including state inspection. Those provisions are under the purview of the North Carolina Division of Land Resources. The division has completed their initial inspections of all of PEC's dams. No significant issues were found.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. On June 21, 2010, the EPA proposed two options for new rules to regulate coal combustion products. The first option would create a comprehensive program of federally-enforceable requirements for coal combustion products management and disposal as hazardous waste. The other option would have the EPA set performance standards for coal combustion products management facilities and regulate disposal of coal combustion products as non-hazardous waste. The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. The 90-day public comment period ends on September 20, 2010, and a final rule is expected in 2011. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require reductions in air emissions of NOx, SO2, carbon dioxide (CO2) and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment installed pursuant to the provisions of CAIR, Clean Air Visibility Rule (CAVR) and mercury regulations, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. As discussed in Note 7B of the 2009 Form 10-K, PEC plans to retire, no later than December 31, 2017, its remaining coal-fired generating facilities in North Carolina totaling 1,500 MW that do not have scrubbers and replace the generation capacity with new natural gas-fueled generating facilities, which will help the utility to comply with the final Clean Smokestacks Act SO2 emissions target that begins in 2013. We are continuing to evaluate various design, technology, generation and fuel options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expense increases with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; the North Carolina retail portion of all other O&M expense is currently recoverable through base rates. On February 11, 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental O&M expenses that PEC incurs in connection with its environmental compliance control facilities.

Clean Air Interstate Rule

The CAIR issued by the EPA on March 10, 2005, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR in 2007.

The air quality controls installed to comply with NOx requirements under certain sections of the Clean Air Act (CAA) and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for our North Carolina units at PEC. PEC and PEF met the 2009 phase I requirements for NOx and anticipate meeting the 2010 phase I requirements of CAIR for NOx and SO2 with a combination of emission reductions resulting from in-service emission control equipment and emission allowances. PEF's Crystal River Unit No. 4 (CR4) equipment was placed in service in May 2010 and PEF's Crystal River Unit No. 5 (CR5) equipment was placed in service in 2009.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. On August 2, 2010, the EPA published the proposed Transport Rule, which is the regulatory program that will replace CAIR when finalized. The proposed Transport Rule contains new emissions trading programs for NOx and SO2 emissions as well as more stringent overall emissions targets. The EPA plans to finalize the new rule in the spring of 2011. Due to significant investments in NOx and SO2 emissions controls and fleet modernization projects completed or underway, we believe both PEC and PEF are well positioned to comply with the Transport Rule. The outcome of the EPA's rulemaking cannot be predicted. Because the D.C. Court of Appeals' December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill BART for NOx and SO2 for BART-affected units under the CAVR. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO2 emissions in addition to particulate matter emissions for BART-eligible units.

Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and No. 2 coal-fired steam turbines (CR1 and CR2) and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was originally anticipated to be around 2020. As required, PEF has advised the FDEP of developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2 as discussed in "Other Matters – Nuclear – Potential New Construction." We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

Clean Air Mercury Rule

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that set mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encouraged a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology (MACT) approach for limiting mercury emissions from coal-fired power plants. On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the CAMR. The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a MACT standard consistent with the agency's original listing determination. The United States District Court for the District of Columbia has issued an order requiring the EPA to issue a final MACT standard for power plants by November 16, 2011. In addition, North Carolina adopted a state specific requirement. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeals' December 23, 2008 decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for NOx and SO2. Should this determination change as the Transport Rule is promulgated, CAVR compliance eventually may require consideration of NOx and SO2 emissions in addition to particulate matter emissions for BART-eligible units. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, the FDEP has not determined the level of additional controls PEF may need to implement. The outcome of these matters cannot be predicted.

Compliance Strategy

Both PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with NOx requirements under certain sections of the CAA and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, resulted in a reduction of the costs to meet PEC's CAIR requirements.

PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions have been placed in service. PEF's CR5 project was placed in service in 2009 and the CR4 project was placed in service in May 2010.

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (see discussion above regarding the vacating of the CAMR and remanding of the CAIR and its potential impact on CAVR). PEF's April 1, 2010 filing with the FPSC for true-up of final 2009 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.1 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote Plant, CR4 and CR5. The majority of the $1.1 billion estimated total project cost related to CR4 and CR5 projects, which have been placed in service. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet compliance requirements of the final Transport Rule. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. PEC is continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013. Additional compliance plans for PEC and PEF to meet the requirements of the Transport Rule will be determined upon finalization of the rule. As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed and we cannot predict the impact that the EPA’s further proceedings will have on our compliance with the CAVR requirements. Compliance plans to meet the requirements of a revised or new implementing rule for mercury will be determined upon finalization of the rule. Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act as discussed below, will be determined upon finalization of the rule. The timing and extent of the costs for future projects will depend upon final compliance strategies. However, we believe that future costs to comply with new or subsequent rule interpretations could be significant.

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

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the CAA, asking the federal government to force fossil fuel-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina’s ability to meet National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In 2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency’s denial. In 2009, the D.C. Court of Appeals remanded the EPA’s denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

In 2006, the EPA announced changes to the NAAQS for particulate matter. The changes in particulate matter standards did not result in designation of any additional nonattainment areas in PEC’s or PEF’s service territories. Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. The outcome of this matter cannot be predicted.

In 2008, the EPA revised the 8-hour primary and secondary standards for the NAAQS for ground-level ozone. Additional nonattainment areas may be designated in PEC’s and PEF’s service territories as a result of these revised standards. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The EPA requested the D.C. Court of Appeals to suspend proceedings in the case while the EPA evaluates whether to maintain, modify or otherwise reconsider the revised NAAQS. In September 2009, the EPA announced that it is reconsidering the level of the ozone NAAQS. The EPA originally indicated plans to designate nonattainment areas for these standards by March 2010. However, the EPA announced that it will stay those designations until after its reconsideration has been completed.

On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. The EPA plans to finalize the revisions by August 31, 2010, and to designate nonattainment areas by August 2011. The proposed revisions are significantly more stringent than the current NAAQS. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide. Since 1971, when the first NAAQS were promulgated, the standard for nitrogen dioxide has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. The EPA plans to designate nonattainment areas by January 2012. Currently, there are no monitors reporting violation of the new standard in PEC's or PEF's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas. The outcome of this matter cannot be predicted.

On June 22, 2010, the EPA published the final new 1-hour NAAQS for SO2, which sets the limit at 75 parts per billion. The primary NAAQS on a 24-hour average basis and annual average will be eliminated under the new rule. The new 1-hour standard is a significant increase in the stringency of the standard and increases the risk of nonattainment, especially near uncontrolled coal-fired facilities. In addition, for the first time the EPA plans to use air quality modeling along with monitoring data in determining whether areas are attaining the new standard, which is likely to expand the number of nonattainment areas. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

Water Quality

1. General

As a result of the operation of certain pollution control equipment required to comply with the air quality issues outlined above, new sources of wastewater discharge will be generated at certain affected facilities. Integration of these new wastewater discharges into the existing wastewater treatment processes is currently ongoing and will result in permitting, construction and treatment requirements imposed on the Utilities now and into the future. The future costs of complying with these requirements could be material to our or the Utilities' results of operations or financial position.

On September 15, 2009, the EPA concluded after a multi-year study of power plant wastewater discharges that current regulations have not kept pace with changes in the electric power industry since the regulations were issued in 1982, including addressing impacts to wastewater discharge from operation of air pollution control equipment. As a result, the EPA has announced that it plans to revise the regulations that govern wastewater discharge, which may result in operational changes and additional compliance costs in the future. The outcome of this matter cannot be predicted.

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

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004.

A number of states, environmental groups and others sought judicial review of the July 2004 rule. In 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA, and the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. Several parties filed petitions for writ of certiorari to the U.S. Supreme Court. On April 1, 2009, the U.S. Supreme Court issued its opinion holding that the EPA, in selecting the "best technology" pursuant to Section 316(b), does have the authority to reject technology when its costs are "wholly disproportionate" to the benefits expected. Also, the U.S. Supreme Court held that EPA's site-specific variance procedure (contained in the July 2004 rule) was permissible in that the procedure required testing to determine whether costs would be "significantly greater than" the benefits before a variance would be considered. As a result of these developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule after it is established by the EPA. Costs of compliance with a revised or new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our cost estimates to comply with the July 2004 rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. As discussed under "Other Matters – Regulatory Environment," on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national REPS. The U.S. Senate is considering similar proposals. Final legislation will depend upon changes made during the legislative process to the provisions and the manner in which key provisions are implemented, including for the regulation of carbon. In addition, the Obama administration has begun the process of regulating GHG emissions through use of the CAA. On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority under the CAA to regulate CO_2 emissions from new automobiles. On December 15, 2009, the EPA announced that six GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the CAA. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of final legislation, if enacted, and additional regulation resulting from other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate GHG emissions that would be presented to the legislature no earlier than January 2010. The FDEP is currently in the process of studying GHG policy options and the potential economic impacts, but it has not developed a regulation for the consideration of the legislature. As discussed under "Clean Smokestacks Act," on July 31, 2009, the governor of North Carolina signed into law a bill that may impact PEC's Clean Smokestacks Act compliance plans. While state-level study groups have been active in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect on February 16, 2005, the United States has not adopted it. In December 2009, the United Nations Framework Convention on Climate Change convened the 15th Conference of the Parties to conduct further negotiations on GHG emissions reductions. At the conclusion of the conference, a number of the parties, including the United States, entered into a nonbinding accord calling upon the parties to submit emission reduction targets for 2020 to the United Nations Framework Convention on Climate Change Secretariat by the end of January 2010. On January 28, 2010, President Obama submitted a proposal to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future Congressional action.

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol, potential new international treaties or federal or state proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time.

On September 22, 2009, the EPA issued the final GHG emissions reporting rule, which establishes a national protocol for the reporting of annual GHG emissions. Facilities that emit greater than 25,000 metric tons per year of GHGs must report emissions by March 31 of each year beginning in 2011 for year 2010 emissions. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review those denials of waiver requests. On June 30, 2009, the EPA granted California's waiver request, enabling the state to enforce its GHG emissions standards for new motor vehicles, beginning with the current model year. Additional states proposed to set similar standards as a result of the decision. The federal government, states, and automakers developed an agreement to establish GHG emissions standards for new light-duty vehicles at the national level. On April 1, 2010, the EPA and the National Highway Transportation Safety Administration jointly announced the first regulation of GHG emissions from new vehicles. The EPA is regulating mobile source GHG emissions under Section 202 of the CAA, which according to the EPA also results in stationary sources, such as coal-fired power plants, being subject to regulation of GHG emissions under the CAA. On March 29, 2010, the EPA issued an interpretation that stationary source GHG emissions will be subject to regulation under the CAA beginning in January 2011. On May 13, 2010, the EPA issued the final "tailoring rule," which establishes the thresholds for applicability of the Prevention of Significant Deterioration program permitting requirements for GHG emissions from stationary sources such as power plants and manufacturing facilities. Prevention of significant deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. The tailoring rule raises the permitting applicability threshold to 75,000 tons per year. The EPA has stated that the permitting requirements for GHG emissions from stationary sources will begin on January 2, 2011. These developments are likely to require PEC and PEF to address GHG emissions in air quality permits. The impact of these developments cannot be predicted.

SYNTHETIC FUELS TAX CREDITS

Historically, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The synthetic fuels tax credit program expired at the end of 2007, and the synthetic fuels businesses were abandoned and reclassified to discontinued operations.

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code effective January 1, 2006. The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removed the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a one-year carry back period and a 20-year carry forward period.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, of which $1.085 billion has been used through June 30, 2010, to offset regular federal income tax liability and $806 million is being carried forward as deferred tax credits.

See Note 13C and Item 1A, "Risk Factors," to the 2009 Form 10-K for additional discussion related to our previous synthetic fuels operations.

DEEPWATER HORIZON OIL SPILL

Three of PEF's four plants on the Gulf Coast have intake canals that bring water from the Gulf of Mexico to be used for cooling purposes and returned to the canal. We do not believe that our power plants are at risk of shutting down as a result of oil from the Deepwater Horizon oil spill interfering with the facilities' intake structures. We are actively monitoring current models of the projected trajectory of the oil spill. We are in communication with the U.S. Coast Guard, local and state officials, BP, other utilities and our oil spill-response contractors daily. Our coastal power plants maintain a boom system for their intake canals, which protects from seaweed, debris and other materials that enter the canals from the Gulf of Mexico. We are also using boats, nets and absorbent materials to regularly check for oil. In the event a small volume of oil passes through our protective boom system, we could clean and restore our equipment to ensure continued operation. We would only need to shut down our power plants if large volumes of oil passed our protective measures and clogged our intake structures, heat exchangers and other equipment to a point where we could no longer operate them.

LEGAL

We are subject to federal, state and local legislation and court orders. The specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures are discussed in detail in Note 13C.

NEW ACCOUNTING STANDARDS

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

PEC

The following MD&A and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review “Safe Harbor for Forward-Looking Statements” included within this Form 10-Q and Item 1A, “Risk Factors,” to the 2009 Form 10-K for a discussion of the factors that may impact any such forward-looking statements made herein.

RESULTS OF OPERATIONS

This information is incorporated herein by reference to “Results of Operations” in Progress Energy’s MD&A, insofar as it relates to PEC.

LIQUIDITY AND CAPITAL RESOURCES

This information is incorporated herein by reference to “Liquidity and Capital Resources” in Progress Energy’s MD&A, insofar as it relates to PEC.

Net cash provided by operating activities increased $71 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The increase was primarily due to $145 million lower cash used for inventory primarily due to a change in generation mix and higher coal consumption as a result of favorable weather that was fulfilled through 2010 usage of inventory from year-end 2009 and a $63 million increase from accounts payable driven by the timing of payments to vendors for increased purchases of fuel and purchased power resulting from outages and favorable weather. These impacts were partially offset by an $81 million increase from receivables primarily due to increased revenues driven by favorable weather and a $71 million decrease from the recovery of deferred fuel costs as a result of higher current year fuel expenses and lower fuel rates.

Net cash used by investing activities decreased $35 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The decrease was primarily due to a $277 million change in advances to affiliated companies, partially offset by a $178 million increase in capital expenditures primarily related to the Wayne County, Richmond County and Sutton generation sites and a $64 million increase in nuclear fuel additions primarily related to one additional refueling outage for 2010 compared to 2009.

Net cash used by financing activities decreased $65 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The decrease was primarily due to the $400 million payment at maturity of PEC’s 5.95% Senior Notes in 2009, the $150 million lower dividend payments to the Parent and the $110 million repayment of commercial paper outstanding in 2009. These payments were partially offset by proceeds from the $600 million issuance of long-term debt in 2009.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEC may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 9 and Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

This information is incorporated herein by reference to “Contractual Obligations” in Progress Energy’s MD&A, insofar as it relates to PEC.

OTHER MATTERS

This information is incorporated herein by reference to “Other Matters” in Progress Energy’s MD&A, insofar as it relates to PEC.

PEF

The following MD&A and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" included within this Form 10-Q and Item 1A, "Risk Factors," to the 2009 Form 10-K for a discussion of the factors that may impact any such forward-looking statements made herein.

Other than as discussed below, the information called for by Item 2 is omitted pursuant to Instruction H(2)(c) to Form 10-Q (Omission of Information by Certain Wholly Owned Subsidiaries).

RESULTS OF OPERATIONS

This information is incorporated herein by reference to "Results of Operations" in Progress Energy's MD&A, insofar as it relates to PEF.

LIQUIDITY AND CAPITAL RESOURCES

This information is incorporated herein by reference to "Liquidity and Capital Resources" in Progress Energy's MD&A, insofar as it relates to PEF.

Net cash provided by operating activities increased $165 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The increase was primarily due to a $226 million increase in income tax receipts, net; an $82 million increase from accounts payable driven by the timing of payments to vendors for increased purchases of fuel and purchased power resulting from outages and favorable weather; and $59 million lower cash used for inventory primarily due to higher coal consumption as a result of favorable weather and lower purchases as a result of decreased purchase requirements on long-term contracts. These impacts were partially offset by $195 million decrease from the recovery of deferred fuel costs as a result of lower fuel rates and higher current year fuel expenses and a $65 million increase in cash collateral posted with counterparties on derivative contracts as discussed under Progress Energy's MD&A, "Liquidity and Capital Resources".

Net cash used by investing activities decreased $249 million for the six months ended June 30, 2010, when compared to the same period in the prior year, primarily due to lower capital expenditures for environmental compliance and nuclear projects.

Net cash provided by financing activities decreased $318 million for the six months ended June 30, 2010, when compared to the same period in the prior year. The decrease was primarily due to a $620 million change in advances from affiliates and a $310 million contribution from the Parent in 2009. These impacts were partially offset by the $300 million net increase in first mortgage bonds outstanding in 2010 and the $371 million repayment of commercial paper outstanding in 2009. PEF's 2010 financing activities are further described under Progress Energy's MD&A, "Liquidity and Capital Resources."

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEF may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 9 and Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

This information is incorporated herein by reference to “Contractual Obligations” in Progress Energy’s MD&A, insofar as it relates to PEF.

OTHER MATTERS

This information is incorporated herein by reference to “Other Matters” in Progress Energy’s MD&A, insofar as it relates to PEF.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties (See Note 9). Both PEC and PEF also have limited counterparty exposure for commodity hedges (primarily gas and oil hedges) by spreading concentration risk over a number of counterparties.

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review Item 1A, "Risk Factors," to the 2009 Form 10-K and "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

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

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

PROGRESS ENERGY

Other than described below, the various risks that we are exposed to have not materially changed since December 31, 2009.

INTEREST RATE RISK

Our debt portfolio and our exposure to changes in interest rates at June 30, 2010, have changed from December 31, 2009. The total notional amount of fixed rate long-term debt at June 30, 2010, was $11.529 billion, with an average interest rate of 6.11% and fair market value of $13.0 billion. The total notional amount of fixed rate long-term debt at December 31, 2009, was $11.245 billion, with an average interest rate of 6.12% and fair market value of $12.1 billion. The total notional amount of variable rate long-term debt at June 30, 2010, was $861 million, with an average interest rate of 0.55% and fair market value of $0.9 billion. The total notional amount of variable rate long-term debt at December 31, 2009, was $961 million, with an average interest rate of 0.48% and fair market value of $1.0 billion.

In addition to our variable rate long-term debt, we typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. At June 30, 2010, we had no outstanding commercial paper and no loans outstanding under our RCA facilities. At December 31, 2009, we had $140 million of outstanding commercial paper and no loans outstanding under our RCA facilities. At June 30, 2010, and December 31, 2009, approximately 7 percent and 9 percent, respectively, of consolidated debt was in floating rate mode.

Based on our variable rate long-term debt balances at June 30, 2010, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $9 million.

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

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates.

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

In accordance with GAAP, interest rate derivatives that qualify as hedges are separated into one of two categories: cash flow hedges or fair value hedges. Cash flow hedges are used to reduce exposure to changes in cash flow due to fluctuating interest rates. Fair value hedges are used to reduce exposure to changes in fair value due to interest rate changes.

The following table summarizes the terms, fair market values and exposures of our interest rate derivative instruments. All of the positions included in the table consist of forward starting swaps used to mitigate exposure to interest rate risk in anticipation of future debt issuances.

Cash Flow Hedges (dollars in millions)	Notional Amount	Mandatory Settlement	Pay	Receive (a)	Fair Value	Exposure (b)
Parent						
Risk hedged at June 30, 2010						
Anticipated 10-year debt issue	$ 300	2011	4.15 %	3-month LIBOR	$ (23)	$ (7)
Anticipated 10-year debt issue	200	2012	4.20 %	3-month LIBOR	(8)	(5)
Risk hedged at December 31, 2009						
Anticipated 10-year debt issue	$ 150	2011	4.03 %	3-month LIBOR	$ 6	$ (3)
PEC						
Risk hedged at June 30, 2010						
Anticipated 10-year debt issue	$ 100	2011	4.31 %	3-month LIBOR	$ (9)	$ (2)
Anticipated 10-year debt issue	200	2012	4.27 %	3-month LIBOR	(8)	(4)
Anticipated 10-year debt issue	50	2013	4.43 %	3-month LIBOR	(2)	(1)
Risk hedged at December 31, 2009						
Anticipated 10-year debt issue	$ 100	2012	4.07 %	3-month LIBOR	$ 8	$ (2)
PEF						
Risk hedged at June 30, 2010						

Anticipated 10-year debt issue	$	150	2011	4.18	%	3-month LIBOR	$	(10	)	$	(4	)
Anticipated 10-year debt issue		50	2013	4.30	%	3-month LIBOR		(2	)		(1	)
Risk hedged at December 31, 2009												
Anticipated 10-year debt issue	$	75	2010	3.48	%	3-month LIBOR	$	5		$	(2	)

(a) 3-month LIBOR rate was 0.53% at June 30, 2010, and 0.25% at December 31, 2009.
(b) Exposure indicates change in value due to 25 basis point unfavorable shift in interest rates.

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 June 30, 2010 and December 31, 2009, the fair value of these funds was $1.341 billion and $1.367 billion, respectively, including $859 million and $871 million, respectively, for PEC and $482 million and $496 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.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At June 30, 2010 and December 31, 2009, the fair value of CVOs was $15 million. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analyses performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A hypothetical 10 percent increase in the June 30, 2010 market price would result in a $2 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

COMMODITY PRICE RISK

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

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value. We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. At June 30, 2010, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

See Note 9 for additional information with regard to our commodity contracts and use of economic and cash flow derivative financial instruments.

PEC

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

PEC has certain market risks inherent in its financial instruments, which arise from transactions entered into in the normal course of business. PEC's primary exposures are changes in interest rates with respect to long-term debt and commercial paper, fluctuations in the return on marketable securities with respect to its NDT funds and changes in energy-related commodity prices. Other than discussed above, PEC's exposure to these risks has not materially changed since December 31, 2009.

PEF

Other than as discussed above, the information called for by Item 3 is omitted pursuant to Instruction H(2)(c) to Form 10-Q (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 4. CONTROLS AND PROCEDURES

PROGRESS ENERGY

Pursuant to the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of management, including our Chairman, President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting during the quarter ended June 30, 2010, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 4T. CONTROLS AND PROCEDURES

PEC

Pursuant to the Securities Exchange Act of 1934, PEC carried out an evaluation, with the participation of its management, including PEC’s Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEC’s disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEC’s Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by PEC in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to PEC’s management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in PEC’s internal control over financial reporting during the quarter ended June 30, 2010, 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 June 30, 2010, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Legal aspects of certain matters are set forth in PART I, Item 1 (See Note 13C).

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A, "Risk Factors," to the 2009 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in the 2009 Form 10-K are not the only risks facing us.

ITEM 2. UNREGISTERED SALE OF EQUITY SECURITIES AND USE OF PROCEEDS

RESTRICTED STOCK UNIT AWARD PAYOUTS

(a) Securities Delivered. On May 4, 2010, June 3, 2010, June 9, 2010 and June 25, 2010, 162 shares, 1,737 shares, 419 shares and 459 shares, respectively, of our common stock were delivered to certain former employees pursuant to the terms of the Progress Energy 2002 and 2007 Equity Incentive Plans (individually and collectively, the "EIP") which have been approved by Progress Energy's shareholders. Additionally, on May 26, 2010 and June 22, 2010, 106 shares, and 931 shares, respectively, of our common stock were delivered to certain current employees pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

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

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

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

PERFORMANCE SHARE SUB-PLAN AWARD PAYOUTS

(a) Securities Delivered. On April 23, 2010, 742 shares of our common stock were delivered to certain current and former employees pursuant to the terms of the EIP. On April 27, 2010 and May 7, 2010, 518 and 598 shares, respectively, of our common stock were delivered to a former employee pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

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

(c) Consideration. The performance share awards were granted to provide an incentive to the current and former employees to exert their utmost efforts on our behalf and thus enhance our performance while aligning the employees' interests with those of our shareholders.

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

ISSUER PURCHASES OF EQUITY SECURITIES FOR SECOND QUARTER OF 2010

Period	(a) Total Number of Shares (or Units) Purchased (1)(2)(3)(4)	(b) Average Price Paid Per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (1)
April 1 – April 30	148,104	$ 39.1980	N/A	N/A
May 1 – May 31	525,140	38.3875	N/A	N/A
June 1 – June 30	308,825	39.3503	N/A	N/A
Total	982,069	38.8125	N/A	N/A

(1) At June 30, 2010, Progress Energy does not have any publicly announced plans or programs to purchase shares of its common stock.

(2) The plan administrator purchased 653,479 shares of our common stock in open-market transactions to meet share delivery obligations under the 401(k).

(3) The plan administrator purchased 312,051 shares of our common stock in open-market transactions to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation.

(4) Progress Energy withheld 15,225 shares of our common stock during the second quarter of 2010 to pay taxes due upon the payout of certain Restricted Stock awards, Restricted Stock Unit awards and Performance Share Sub-Plan awards pursuant to the terms of the Company's 2002 and 2007 Equity Incentive Plans. Progress Energy withheld 9,171 shares of our common stock at an average price per share of $38.9835 during the first quarter of 2010 to pay taxes due upon the vesting of certain Restricted Stock awards, which are not reflected in the table above.

ITEM 5. OTHER INFORMATION

As allowed under the SEC's implementation guidelines contained in the Interactive Data to Improve Financial Reporting Final Rule, we will furnish Exhibit 101 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 in Amendment No. 1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010, within the initial 30-day grace period following our filing date. No other changes or additions to the financial statements or disclosure provided in this Form 10-Q are expected in connection with the Amendment No. 1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010.

ITEM 6. EXHIBITS

(a) Exhibits

Exhibit Number	Description	Progress Energy	PEC	PEF
10(a)	Amended and Restated Management Incentive Compensation Plan of Progress Energy, Inc., effective as of September 1, 2010	X	X	X
10(b)	Amended and Restated Management Deferred Compensation Plan of Progress Energy, Inc., effective as of September 1, 2010	X	X	X
31(a)	302 Certifications of Chief Executive Officer	X		
31(b)	302 Certifications of Chief Financial Officer	X		
31(c)	302 Certifications of Chief Executive Officer		X	
31(d)	302 Certifications of Chief Financial Officer		X	
31(e)	302 Certifications of Chief Executive Officer			X
31(f)	302 Certifications of Chief Financial Officer			X
32(a)	906 Certifications of Chief Executive Officer	X		
32(b)	906 Certifications of Chief Financial Officer	X		
32(c)	906 Certifications of Chief Executive Officer		X	
32(d)	906 Certifications of Chief Financial Officer		X	
32(e)	906 Certifications of Chief Executive Officer			X
32(f)	906 Certifications of Chief Financial Officer			X

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the 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 d/b/a PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
(Registrants)

Date: August 6, 2010

By: /s/ Mark F. Mulhern
Mark F. Mulhern
Senior Vice President and Chief Financial Officer

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer and Controller
Progress Energy, Inc.
Chief Accounting Officer
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
Florida Power Corporation d/b/a Progress Energy Florida, Inc.