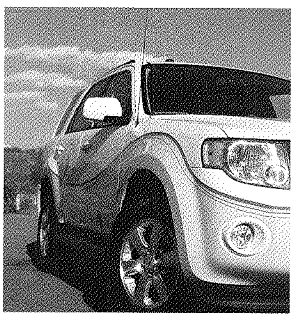
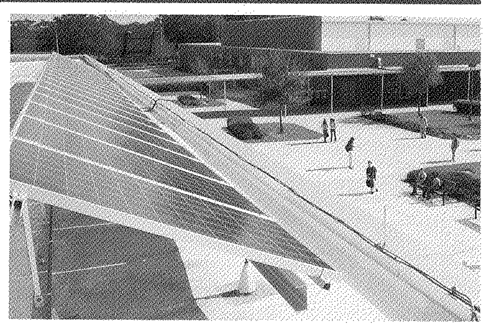
MANAGING THE PRESENT.

CREATING THE FUTURE.



THE POWER TO DO BOTH.

2009 Annual Report and Notice of Annual Meeting and Proxy Statement

Progress Energy

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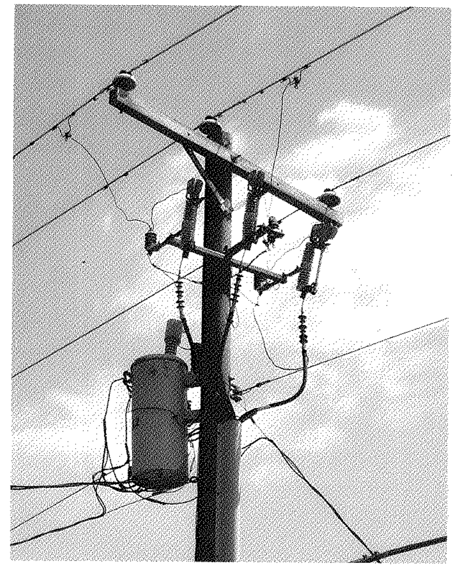
a message from our CEO

DEAR SHAREHOLDERS: Progress Energy lived up to its commitments in 2009 despite the hard economic realities in our nation and region. We delivered reliable, responsive service to customers and solid results to shareholders. Now, we are focused on effectively managing through the challenges and uncertainties of 2010 while taking important steps to create a successful future for our communities and company.



This report to you in early spring 2010 comes as our nation is slowly climbing out of a deep economic recession. Most of us, no doubt, have gained a new understanding of volatility and financial risk since late 2008, whether as an investor, a business owner or an individual trying to make a living.

I am proud of the way our employees and management team are handling these turbulent times. We are being both steady in the present storm and forward looking – controlling what we can control, aggressively managing costs and preparing for the future. We always keep in mind that millions of people count on us for an essential service or a quarterly dividend (in many cases, both), and for being a responsible corporate citizen.

Delivering reliable results

Progress Energy posted good financial results in a challenging year. We delivered a 10 percent total return to shareholders in 2009 and achieved ongoing earnings per share in our original targeted range for the fourth year in a row. Our company also has maintained its long record of commitment to the dividend, paying a dividend for more than 250 consecutive quarters.

Throughout this period, our two electric utilities – Progress Energy Carolinas and Progress Energy Florida – have continued to excel in our core mission of serving customers. This winter we met the challenge of extreme cold and record-breaking peak demand in the Carolinas and Florida and mobilized effectively to deal with severe storms, creatively using Twitter and other social media to provide timely updates.

We also brought into service additional peaking-generation capacity in North Carolina and completed a major oil-to-gas repowering project in Florida. This Bartow modernization project last summer was an outstanding success in terms of project management, capacity expansion and emissions reduction.

Our company recently received positive external recognition for environmental stewardship and customer service. Progress Energy was named to the Dow Jones Sustainability Index for the fifth consecutive year, and Progress Energy Carolinas was ranked number one in customer satisfaction in the South region for the second year in a row – number one among large utilities nationally – in the latest J.D. Power and Associates survey of utilities' business customers.

Managing the present

The financial pressure on our company has gone up another notch or two in 2010 because of a disappointing Florida rate decision early in the year and a still-sluggish economy throughout the nation. These events inevitably affect our earnings and cash flow and have caught the attention of the credit-rating agencies.

In response, we are redoubling our belt-tightening this year: maintaining the dividend, streamlining maintenance, scaling back capital spending and reducing merit and variable-performance pay increases for employees (in fact, no merit pay increase for executives and managers in 2010). This is a shared-sacrifice approach that's neither desirable nor sustainable for long but is necessary for now.

We are also evaluating our regulatory and financial options in Florida and are continuing to do our part to foster a constructive Florida regulatory climate that will enable us to attract the capital required to meet our customer and environmental obligations. Also of note in Florida is the extended repair outage at our Crystal River Nuclear Plant, which we expect to complete midyear.

We are managing these and other challenges in a disciplined way to avoid compromising safety or operational excellence. In this business, we can't afford to be reckless or short-sighted.

Creating the future

At Progress Energy, we believe strongly in the long-term growth prospects of the communities we serve in the Carolinas and Florida. An improving national economy and housing market will enable more people to move to our service areas and more businesses to invest and expand here. So, even as we are making the tough choices to manage today's realities, we are carefully laying the groundwork for the higher growth and better future we see coming.

We intend to remain attractive to the buy-and-hold investors who represent the core of our shareholder base. This investor confidence is essential for us to fund the projects needed to be ready for a growing population and expanding economy as well as to meet the requirements of new energy and environmental policies.

National and state energy policies remain in flux, especially the rules to reduce greenhouse gas emissions and address global climate change. This prolonged uncertainty greatly

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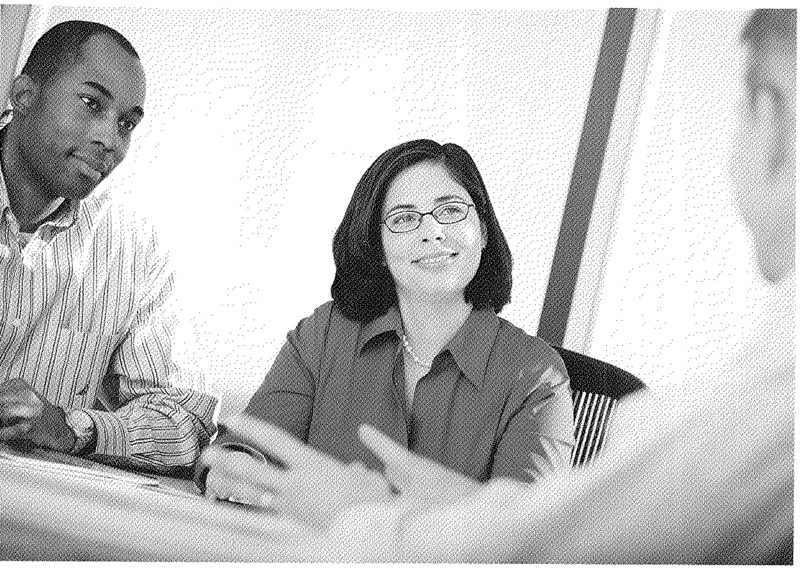
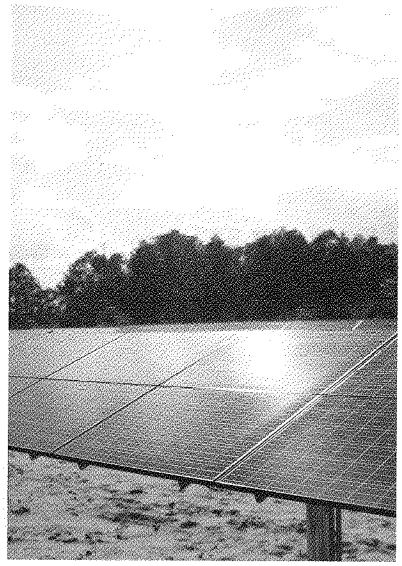




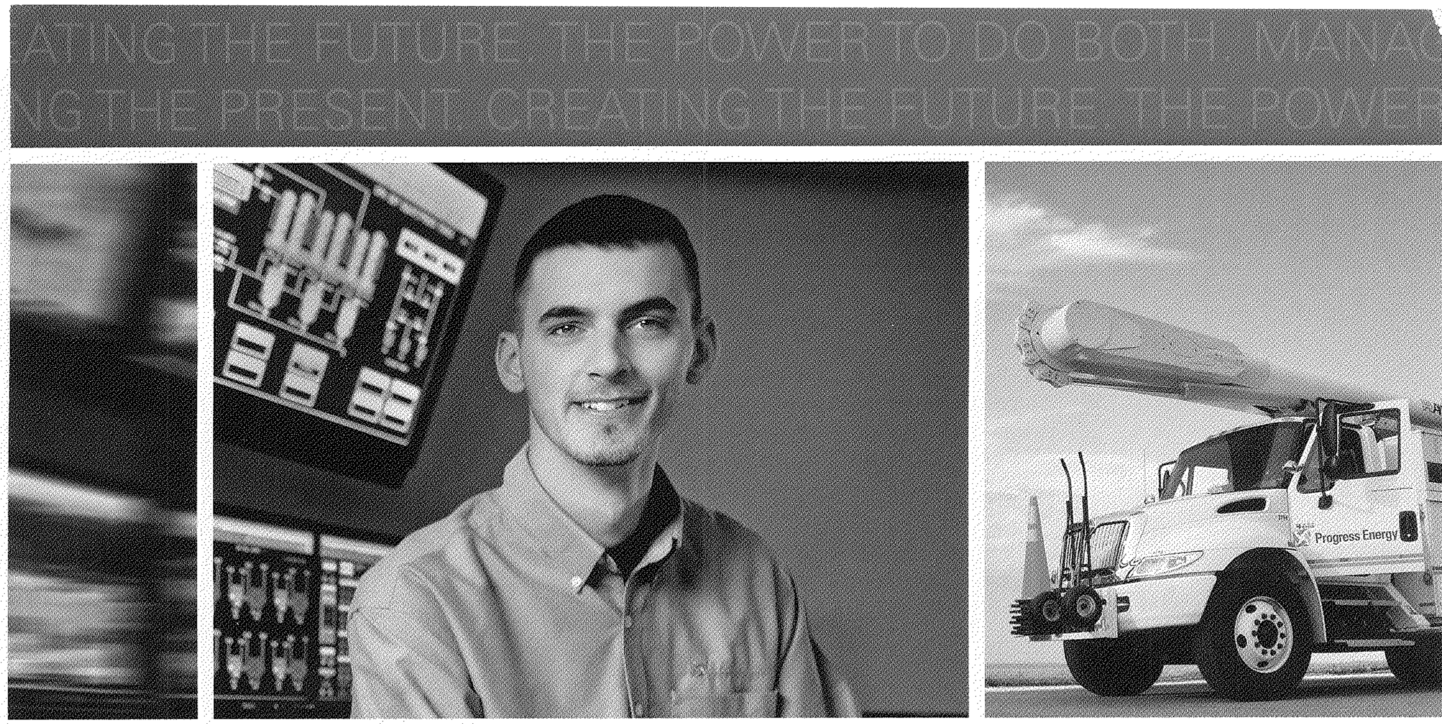
complicates utility planning, but there is a clear sense that clean-energy technologies ranging from renewable to nuclear must be a growing part of our nation's energy future.

Aligned with this direction, we developed a Balanced Solution strategy several years ago. It is a flexible portfolio approach that covers a broad spectrum of initiatives: aggressive energy-efficiency programs, innovative alternative energy projects (e.g., solar rooftop program, biofuels and utility-scale solar) and rapidly emerging technologies (e.g., plug-in electric vehicles), and larger-scale investments in a state-of-the-art power system. These larger investments include the Smart Grid and fossil-fuel fleet modernization in the near-to-mid term and new advanced nuclear generation in the longer term.

Financial highlights

Years ended December 31 *(in millions except per share data)*	**2009**	2008	2007
Financial Data			
Operating revenues	**$9,885**	$9,167	$9,153
Net income attributable to controlling interests	**757**	830	504
Income from continuing operations	**840**	778	702
Ongoing earnings per common share*	**3.03**	2.96	2.71
Reported GAAP earnings per common share	**2.71**	3.17	1.96
Average common shares outstanding	**279**	262	257
Common Stock Data			
Return on average common stock equity (percent)	**8.13**	9.59	5.97
Book value per common share	**$33.53**	$32.97	$32.41
Market value per common share (closing)	**$41.01**	$39.85	$48.43

**See page 128 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*



A specific example of our strategy is the fleet-modernization announcement we made late last year to retire our 11 oldest coal-fired generating units in the Carolinas – about a third of our coal fleet there. We will replace that nearly 1,500 megawatts of capacity with highly efficient combined-cycle natural-gas turbines and possibly biomass conversion. This has many benefits: a substantial reduction in air emissions (including those linked to climate change), less exposure to issues with coal-ash management, and a positive boost to both local economic development and utility earnings. We believe this is a positive, responsible step no matter what happens with future climate policy.

Complementing our Balanced Solution approach is our Continuous Business Excellence strategy for making internal efficiency and productivity improvements. Unlike short-term belt-tightening, this is a systematic, long-term effort to engage employees in achieving sustainable cost savings and other improvements. We're seeing encouraging early success and expect much more in the years ahead.

In assessing the overall situation Progress Energy faces, I am confident we will meet our short-term priorities while also producing long-term value for our customers and shareholders. In other words, we will manage the present and create the future.

Integrity, transparency and trust

In closing, I want to assure you that acting with integrity remains a core value of this company – behavior that includes not only being honest and ethical in our business practices but also being open in our communications and reliable in doing what we say we will do. We are committed to earning your confidence and trust year after year, in good times and bad – both by what we do and how we do it.

Thank you for your interest in Progress Energy.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2010

EXECUTIVE AND SENIOR OFFICERS

William D. Johnson
Chairman, President and Chief Executive Officer
Progress Energy, Inc.

John R. McArthur
Executive Vice President and Corporate Secretary
Progress Energy, Inc.

Mark F. Mulhern
Senior Vice President and Chief Financial Officer
Progress Energy, Inc.

Jeffrey J. Lyash
Executive Vice President – Corporate Development
Progress Energy, Inc.

Vincent M. Dolan
President and Chief Executive Officer
Progress Energy Florida, Inc.

Lloyd M. Yates
President and Chief Executive Officer
Progress Energy Carolinas, Inc.

Jeffrey A. Corbett
Senior Vice President – Energy Delivery
Progress Energy Carolinas, Inc.

Michael A. Lewis
Senior Vice President – Energy Delivery
Progress Energy Florida, Inc.

James Scarola
Senior Vice President and
Chief Nuclear Officer
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

Frank A. Schiller
Senior Vice President – Compliance
and General Counsel
Progress Energy, Inc.

Chief Compliance Officer
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

Paula J. Sims
Senior Vice President – Power Operations
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

FINANCIAL REPORT

The matters discussed throughout this Annual Report 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 we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

In addition, examples of forward-looking statements discussed in this Annual Report include, but are not limited to, "Management's Discussion and Analysis of Financial Condition and Results of Operations" including, but not limited to, statements under the following headings: a) "Strategy" about our future strategy and goals; b) "Results of Operations" about trends and uncertainties; c) "Liquidity and Capital Resources" about operating cash flows, future liquidity requirements and estimated capital expenditures through the year 2012; and d) "Other Matters" about the effects of new environmental regulations, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction and our synthetic fuels tax credits.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and energy policy; our ability to recover eligible costs and earn an adequate return on investment through the regulatory process; the ability to successfully operate electric generating facilities and deliver electricity to customers; the impact on our facilities and businesses from a terrorist attack; the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and regulations; risks associated with climate change; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; our 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 us; our ability to maintain our current credit ratings and the impacts in the event our 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 our filings with the SEC. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can management assess the effect of each such factor on Progress Energy.

The following Management's Discussion and Analysis of Financial Condition and Results of Operations (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" for a discussion of the factors that may impact any such forward-looking statements made herein. 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." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities." MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements.

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.

Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

INTRODUCTION

Our reportable business segments are PEC and PEF, and their primary operations are the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The "Corporate and Other" segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative requirements as a separate reportable business segment.

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. We own two electric utilities that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to attractive wholesale markets in the eastern United States. The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. Please review "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

We have a strong track record of meeting our financial commitments and delivering operational excellence. We have maintained liquidity and financial stability and sustained our dividend rate during the current economic downturn, and we believe that we have good prospects for growth once the economy begins to recover. An improving national economy may lead to greater mobility for homeowners around the country and a return of migration to the Southeast region that is more consistent with historical levels. The utility industry, as a whole, however, faces significant cost pressures and, in the near term, lower retail electricity sales. In addition, current economic conditions and anticipated higher expenditures (including for environmental compliance, renewable energy standards compliance and new generation and transmission facilities) may subject us to an even higher level of scrutiny from regulators and lead to a more uncertain regulatory environment. We anticipate the need to prepare for a different kind of energy future – one that would include, among other things, reducing carbon emissions and using emerging technologies such as the Smart Grid and electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework to prepare for this new energy future. Additional information about the strategy, including updates on implementation, is included in "Strategic Initiatives" below.

To manage the challenges of the present and prepare for the future, management's priority focus areas for 2010 and beyond are as follows:

- Financial Performance
- Operational Performance
- Organizational Effectiveness
- Regulation and Public Policy
- Strategic Initiatives

The first two priorities are core elements of managing our business. The next two priorities will help enable what we can accomplish in the future. The last priority involves making the right investments to create a strong energy future for Progress Energy and our customers.

FINANCIAL AND OPERATIONAL PERFORMANCE

Effectively managing expenses, deploying capital and enhancing our margin are critical to achieving sustainable earnings growth and attractive long-term returns for our shareholders. We have instituted throughout our organization systematic approaches to achieve sustainable cost savings through enhanced efficiency and productivity. These ongoing cost management initiatives – along with short-term expense management – have enabled us to offset some of the impact of the economic downturn and cost pressures and should yield long-term operations and maintenance (O&M) expense savings and effective capital management. Also, we recognize that our shareholders strongly value our dividend and that it is an integral part of our total shareholder return proposition. Our long-term goal is to achieve a 70 to 75 percent dividend payout ratio, and we are committed to managing the company such that we reach this target while maintaining an attractive, sustainable dividend rate.

Our financial performance depends on the successful operation of the Utilities' electric generating and distribution facilities and reliable delivery of electric service to our customers. Consequently, we strive to excel in safety, operational performance and customer satisfaction. We also focus on rigorous project management in executing our capital program, including large-scale capital projects such as construction of new generating facilities, modernization of existing facilities and environmental compliance as well as programs such as demand-side management (DSM).

Another operational priority is a fleet alignment initiative to strengthen the Utilities' nuclear performance in safely and reliably producing electricity while meeting the highest standards of environmental protection in the most efficient manner. The multi-year initiative implements a new business model for our five nuclear units and is based on industry benchmarking that coordinated, collaborative and standardized operations achieve and sustain a higher level of performance than would be possible if each unit operated autonomously. The goals of the initiative are, among other things, to establish a common vision and set of core values; facilitate common procedures across the fleet to accommodate shared resources and industry best practices; and establish a strong performance-monitoring system that provides feedback to management.

ORGANIZATIONAL EFFECTIVENESS

With our managers and supervisors at all levels, we emphasize demonstrating the leadership behaviors that fully engage our workforce and optimize their performance in executing our strategy. We strive to cultivate an inclusive work environment in which we treat everyone with respect and hold each other to high standards. In addition, we are implementing long-term workforce strategies to prepare for our changing needs and an aging workforce. Our workforce strategy includes recruiting, training and retaining a skilled, diverse workforce that reflects the communities we serve.

REGULATION AND PUBLIC POLICY

PEC and PEF are regulated by the state utility commissions in their state jurisdictions. Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of prudent expenses and a fair return on utility investments. Our business plans include the assumption that the respective public utility commissions will provide reasonable recovery. In 2009, PEC received approval for its coal-to-gas fleet modernization plan discussed in "Strategic Initiatives" as well as multiple DSM, renewable energy and energy-efficiency filings. Also in 2009, PEF successfully sought interim and limited rate relief and nuclear cost recovery in Florida. However, in response to a 2009 base rate case PEF filed with the Florida Public Service Commission (FPSC), in January 2010, the FPSC decided to grant PEF no increase in base rates above what was previously awarded in 2009 for the repowered Bartow Plant (approximately $132 million annual revenue requirements). The FPSC's decision was predicated on its desire to hold down rates. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. We are currently reviewing our regulatory options in Florida. We believe that the FPSC's regulatory action was strongly influenced by the current economic downturn. In a long-term view of Florida's regulatory environment, we believe that as the economy improves, the need to provide for Florida's energy future will have a stronger influence in the FPSC's decision-making process. Consequently, we do not believe the January 2010 decision represents a permanent change to the regulatory environment in Florida.

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Changes in federal and state regulation are currently under consideration for, among others, greenhouse gases (GHG) such as carbon dioxide (CO_2), coal combustion products, mercury and particulate matter. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. However, we anticipate that it could result in significant rate increases over time to recover the compliance costs.

We are dedicated to seeking achievable, affordable climate and energy policies. We evaluate public policy proposals and actively promote initiatives that are achievable but manage the long-term costs to our customers.

STRATEGIC INITIATIVES

Our balanced solution strategy is intended to deploy capital effectively to meet future customer needs and emerging public policies while achieving our financial objectives. It is a three-pronged strategy that focuses on energy efficiency, alternative energy and state-of-the-art power generation. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms implemented by our state jurisdictions. Updates on our implementation of this strategy are discussed below.

First, we are expanding and enhancing our DSM, energy-efficiency and energy conservation programs. We have implemented expanded energy-efficiency programs to our customers and continue to pursue additional initiatives. Federal law enacted in 2009 contains provisions promoting energy efficiency and renewable energy and we have been notified of our selection for Smart Grid grant negotiations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. While this currently represents a small percentage of our total capacity, we will continue to pursue additional contracts for these and other alternative energy sources.

Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating modernization of existing coal plants and the best new generation options, including advanced design nuclear technology and gas-fired combined cycle and combustion turbines. In 2009, we completed the repowering of PEF's Bartow Plant, construction of a new 157-MW combustion turbine at PEC and the installation of pollution control equipment (or scrubbers) on PEF's coal-fired unit, Crystal River Unit No. 5 (CR5), and PEC's Mayo Plant. We also received approval to construct a 600-MW combined cycle dual-fuel facility and a 950-MW combined cycle natural gas-fueled facility at PEC, which are expected to come online in 2011 and 2013, respectively. PEC has filed for approval to construct a 620-MW natural gas-fueled facility. In 2009, we also announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions.

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. In 2008, each Utility filed a combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy).

We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions, as well as existing state legislative policy that is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a COL remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In light of a regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan with respect to Levy.

In summary, we are effectively dealing with today's challenges while taking steps to create long-term value for our customers and shareholders.

RESULTS OF OPERATIONS

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

A reconciliation of "Ongoing Earnings" to GAAP net income attributable to controlling interests is below, followed by an explanation of our non-GAAP financial measurement, "Ongoing Earnings."

communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings. We compute Ongoing Earnings as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges. Some

(in millions except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
For the year ended December 31, 2009					
Ongoing Earnings	**$540**	**$460**	**$(154)**	**$846**	**$3.03**
CVO mark-to-market	**–**	**–**	**19**	**19**	**0.07**
Impairment, net of tax[(a)]	**–**	**–**	**(2)**	**(2)**	**(0.01)**
Plant retirement charge, net of tax[(a)]	**(17)**	**–**	**–**	**(17)**	**(0.06)**
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax[(a)]	**(10)**	**–**	**–**	**(10)**	**(0.04)**
Discontinued operations attributable to controlling interests, net of tax	**–**	**–**	**(79)**	**(79)**	**(0.28)**
Net income (loss) attributable to controlling interests[(b)]	**$513**	**$460**	**$(216)**	**$757**	**$2.71**
For the year ended December 31, 2008					
Ongoing Earnings	$531	$383	$(138)	$776	$2.96
Valuation allowance and related net operating loss carry forward	–	–	(3)	(3)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	57	57	0.22
Net income (loss) attributable to controlling interests[(b)]	$531	$383	$(84)	$830	$3.17
For the year ended December 31, 2007					
Ongoing Earnings	$498	$315	$(118)	$695	$2.71
CVO mark-to-market	–	–	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	(189)	(189)	(0.74)
Net income (loss) attributable to controlling interests[(b)]	$498	$315	$(309)	$504	$1.96

[(a)] Calculated using assumed tax rate of 40 percent.
[(b)] Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $(3) million and $(2) million at PEC and PEF, respectively.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in

of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Historically, Ongoing Earnings for our reportable segments, which are PEC and PEF, have been consistent with the most comparable GAAP measure, net income attributable to controlling interests. In 2009, PEC recorded charges that management determined should be excluded from

PEC's Ongoing Earnings. The charges were related to its planned retirement of certain coal-fired generating units prior to the end of their estimated useful lives and a cumulative prior period adjustment related to certain employee life insurance benefits. The prior period adjustment, which was recorded in the fourth quarter of 2009, was not material to previously issued or current period financial statements. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP.

Overview

FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

For the year ended December 31, 2009, our net income attributable to controlling interests was $757 million, or $2.71 per share, compared to $830 million, or $3.17 per share, for the same period in 2008. The decrease as compared to prior year was due primarily to:

- unfavorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- unfavorable net retail customer growth and usage at the Utilities;
- higher interest expense; and
- higher base depreciation and amortization at the Utilities.

Partially offsetting these items were:

- net impact of returns earned on higher levels of nuclear and environmental cost recovery clause (ECRC) assets at PEF;
- favorable impact of interim and limited base rate relief at PEF;
- depreciation and amortization expense recognized in 2008 at PEC related to North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization expense and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets; and
- favorable weather at the Utilities.

For the year ended December 31, 2008, our net income attributable to controlling interests was $830 million, or $3.17 per share, compared to $504 million, or $1.96 per share, for the same period in 2007. The increase in 2008 as compared to 2007 was due primarily to:

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

Partially offsetting these items were:

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

Progress Energy Carolinas

PEC contributed net income available to parent totaling $513 million, $531 million and $498 million in 2009, 2008 and 2007, respectively. The decrease in net income available to parent for 2009 as compared to 2008 was primarily due to unfavorable net retail customer growth and usage, coal plant retirement charges, higher base depreciation and amortization expense and a cumulative prior period adjustment related to certain employee life insurance benefits, partially offset by Clean Smokestacks Act amortization and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the favorable impact of weather. PEC contributed Ongoing Earnings of $540 million in 2009. There were no Ongoing Earnings adjustments in 2008 and 2007. The 2009 Ongoing Earnings adjustments to net income available to parent were due to PEC recording a $17 million charge, net of tax, for the impact of PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives and recording a $10 million charge, net of tax, for a cumulative prior period adjustment related to certain employee life insurance benefits. Management does not consider these charges to be representative of PEC's fundamental core earnings and excluded these charges in computing PEC's Ongoing Earnings.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to lower purchased power capacity costs due to the expiration of a power buyback agreement, favorable AFUDC and favorable net retail customer growth and usage, partially offset by the unfavorable impact of weather and lower excess generation revenues.

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

REVENUES

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

(in millions)

Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**$1,179**	1.6	$1,160	(1.0)	$1,172
Commercial	**741**	(0.9)	748	0.4	745
Industrial	**374**	(10.1)	416	2.0	408
Governmental	**62**	(3.1)	64	4.9	61
Unbilled	**5**	–	8	–	(1)
Total retail base revenues	**2,361**	(1.5)	2,396	0.5	2,385
Wholesale base revenues	**310**	–	310	(12.7)	355
Total Base Revenues	**2,671**	(1.3)	2,706	(1.2)	2,740
Clause-recoverable regulatory returns	**6**	–	–	–	–
Miscellaneous	**114**	11.8	102	5.2	97
Fuel and other pass-through revenues	**1,836**	–	1,621	–	1,548
Total operating revenues	**$4,627**	4.5	$4,429	1.0	$4,385

PEC's total retail base revenues were $2.361 billion and $2.396 billion for 2009 and 2008, respectively. The $35 million decrease in revenues was due primarily to the $58 million unfavorable impact of net retail customer growth and usage, partially offset by the $23 million favorable impact of weather. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 14,000 increase in the average number of customers for 2009 compared to 2008. However, PEC's rate of residential growth has declined as PEC's average number of customers increased a net 24,000 customers for 2008 compared to 2007. The favorable impact of weather was driven by higher heating and cooling degree days than 2008 of 3 percent and 5 percent, respectively. Additionally, cooling degree days were 6 percent higher than normal in 2009.

PEC's miscellaneous revenues increased $12 million in 2009 primarily due to higher transmission revenues.

PEC's total retail base revenues were $2.396 billion and $2.385 billion for 2008 and 2007, respectively. The $11 million increase in revenues was due primarily to the $34 million favorable impact of net retail customer growth and usage, partially offset by the $28 million unfavorable impact of weather. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal.

PEC's wholesale base revenues were $310 million and $355 million for 2008 and 2007, respectively. The $45 million lower wholesale base revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers.

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

(in millions of kWh)					
Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**17,117**	0.7	17,000	(1.2)	17,200
Commercial	**13,639**	(2.2)	13,941	(0.6)	14,032
Industrial	**10,368**	(9.0)	11,388	(4.3)	11,901
Governmental	**1,497**	2.1	1,466	1.9	1,438
Unbilled	**360**	–	(8)	–	(55)
Total retail kWh sales	**42,981**	(1.8)	43,787	(1.6)	44,516
Wholesale	**13,966**	(2.5)	14,329	(6.4)	15,309
Total kWh sales	**56,947**	(2.0)	58,116	(2.9)	59,825

The decrease in retail kWh sales in 2009 was primarily due to a decrease in average usage per retail customer. PEC's industrial kWh sales have decreased 9.0 percent from 2008, primarily due to continued reductions in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a continued downturn in the lumber and building materials segment as a result of declines in construction. Many of the manufacturers in PEC's service territory have been adversely impacted by the economic conditions, and we expect a relatively slow recovery in industrial sales once the economy begins to recover.

Wholesale kWh sales decreased for 2009 primarily due to decreased excess generation sales resulting from unfavorable market dynamics.

Industrial electric energy sales decreased in 2008 compared to 2007, primarily due to downturns in textile manufacturing and lumber and building materials segment as previously discussed.

PEC has experienced a decline in its retail and wholesale kWh sales due to the economic conditions in the United States. We cannot predict how long these conditions may last or the extent to which they may impact revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $1.909 billion for 2009, which represents a $217 million increase compared to 2008. Fuel used in electric generation increased $334 million to $1.680 billion primarily due to $248 million higher deferred fuel expense and the $86 million net impact of higher fuel costs. The increase in deferred fuel expense was primarily due to the implementation of new fuel rates in North Carolina. The higher fuel costs were primarily due to higher coal prices. Purchased power expense decreased $117 million to $229 million compared to prior year. The decrease was primarily due to lower market purchases of $85 million and lower co-generation of $43 million primarily due to lower system requirements.

Fuel and purchased power expenses were $1.692 billion for 2008, which represents a $9 million increase compared to 2007. Purchased power expense increased $44 million to $346 million compared to 2007. The increase was primarily due to increased economical purchases in 2008 of $78 million, partially offset by the $38 million impact from the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Fuel used in electric generation decreased $35 million to $1.346 billion primarily due to a $116 million decrease in deferred fuel expense, partially offset by increased fuel costs of $81 million. The decrease in deferred fuel expense was primarily driven by a $64 million impact from the implementation of state legislation that expanded the definition of the traditional fuel clause to include costs of commodities such as ammonia and limestone used in emissions control technologies (reagents), transmission charges and non-capacity-related costs of purchases and a $49 million impact related to under-recovered fuel costs. Deferred fuel expense was higher in 2007 primarily due to the collection of fuel costs from customers that had been previously under-recovered. The increase in fuel costs of $81 million was primarily due to an increase in coal prices, partially offset by the impacts of lower system requirements and a change in the generation mix.

Operation and Maintenance

O&M expense was $1.072 billion for 2009, which represents a $42 million increase compared to 2008. This increase was primarily due to coal plant retirement charges of $28 million, higher pension and benefit costs of $12 million and storm costs of $9 million, partially offset by lower emission allowance expense of $13 million resulting from lower system requirements, changes in generation mix and sales of nitrogen oxide (NOx) allowances. PEC recognized coal plant retirement charges ($17 million, net of tax) for the impact of the decision to retire 11 coal-fired units prior to the end of their estimated useful lives (See "Future Liquidity and Capital Resources – PEC Other Matters" and "Other Matters – Energy Demand"). Management determined that such charges should be an exclusion from PEC's Ongoing Earnings.

O&M expense was $1.030 billion for 2008, which represents a $6 million increase compared to 2007. This increase was driven primarily by a $33 million increase in nuclear expenses, of which $18 million relates to refurbishments, preventive maintenance and incremental outage expenses at Brunswick Nuclear Plant (Brunswick). Additionally, O&M increased due to a $7 million increase in estimated environmental remediation expenses (See Note 21A), partially offset by $19 million lower employee benefits and $16 million lower nuclear plant outage and maintenance costs. The decrease in employee benefits was primarily due to the 2007 impact from changes in stock-based compensation plans and higher relative employee incentive goal achievement. The decrease in nuclear plant outage and maintenance costs was primarily due to two nuclear refueling and maintenance outages in 2008 compared to three in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $470 million for 2009, which represents a $48 million decrease compared to 2008. This decrease was primarily attributable to the $52 million of depreciation associated with the accelerated cost-recovery program for nuclear generating assets recognized during 2008 (See Note 7B) and the $15 million of Clean Smokestacks Act amortization recognized in 2008, partially offset by the $21 million impact of depreciable asset base increases. The North Carolina jurisdictional aggregate minimum amount of accelerated cost recovery has been met, and the South Carolina jurisdictional obligation was terminated by the Public Service Commission of South Carolina (SCPSC). PEC does not anticipate recording additional accelerated depreciation in the North Carolina jurisdiction, but will record depreciation over the remaining useful lives of the assets. In accordance with a regulatory order, PEC ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful lives of the assets (See Note 7B).

Depreciation, amortization and accretion expense was $518 million for 2008, which represents a $1 million decrease compared to 2007. This decrease was primarily attributable to $19 million lower Clean Smokestacks Act amortization, $8 million lower GridSouth Transco, LLC (GridSouth) amortization and $3 million lower storm deferral amortization, partially offset by $15 million higher depreciation associated with the accelerated cost-recovery program for nuclear generating assets and the $15 million impact of depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $210 million, $198 million and $192 million in 2009, 2008 and 2007, respectively. The $12 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts taxes due to higher operating revenues and higher property tax rates. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Total Other Income, Net

Total other income, net was $20 million for 2009, which represents a $23 million decrease compared to 2008. This decrease was primarily due to a cumulative prior period adjustment related to certain employee life insurance benefits and lower interest income resulting from lower average eligible deferred fuel balances. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net by $16 million and decreased net income available to parent by $10 million. The prior period adjustment is not material to previously issued or current period financial statements. Management determined that the adjustment should be an exclusion from PEC's Ongoing Earnings.

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

Total Interest Charges, Net

Total interest charges, net was $195 million for 2009, which represents a $12 million decrease compared to 2008. This decrease was primarily due to lower interest rates on variable rate debt, partially offset by higher interest as a result of higher average debt outstanding.

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

Income Tax Expense

Income tax expense was $277 million, $298 million and $295 million in 2009, 2008 and 2007, respectively. The $21 million income tax expense decrease in 2009 compared to 2008 was primarily due to the impact of lower pre-tax income and the $5 million favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified nuclear decommissioning trusts (NDTs) to qualified NDTs. The $3 million income tax expense increase in 2008 compared to 2007 was primarily due to the $14 million impact of higher pre-tax income and the $5 million impact related to the deduction for domestic production activities, partially offset by the $7 million tax impact of employee stock-based benefits and the $7 million impact of the increase in AFUDC equity previously discussed. AFUDC equity is excluded from the calculation of income tax expense.

Progress Energy Florida

PEF contributed net income available to parent and Ongoing Earnings totaling $460 million, $383 million and $315 million in 2009, 2008 and 2007, respectively. The increase in net income available to parent for 2009 as compared to 2008 was primarily due to the higher net impact of returns earned on higher levels of nuclear and ECRC assets to be recovered through respective cost-recovery clauses, the favorable impact of interim and limited base rate relief (See Note 7C) and the favorable impact of weather, partially offset by the unfavorable impact of retail customer growth and usage, higher base depreciation and amortization expense, and higher O&M.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to favorable AFUDC, increased retail base rates and higher wholesale revenues, partially offset by higher interest expense, unfavorable net retail customer growth and usage, higher depreciation and amortization expense excluding recoverable storm amortization, and higher investment losses of certain employee benefit trusts.

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. "Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause-recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We 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 have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

REVENUES

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

(in millions)

Customer Class	2009	% Change	2008	% Change	2007
Residential	**$946**	5.9	$893	3.4	$864
Commercial	**340**	3.7	328	6.8	307
Industrial	**72**	(5.3)	76	5.6	72
Governmental	**87**	6.1	82	5.1	78
Unbilled	**9**	–	(1)	–	1
Total retail base revenues	**1,454**	5.5	1,378	4.2	1,322
Wholesale base revenues	**207**	5.1	197	33.1	148
Total Base Revenues	**1,661**	5.5	1,575	7.1	1,470
Clause-recoverable regulatory returns	**87**	690.9	11	450.0	2
Miscellaneous	**189**	6.2	178	4.7	170
Fuel and other pass-through revenues	**3,314**	–	2,967	–	3,107
Total operating revenues	**$5,251**	11.0	$4,731	(0.4)	$4,749

PEF's total retail base revenues were $1.454 billion and $1.378 billion for 2009 and 2008, respectively. The $76 million increase was primarily due to the $79 million favorable impact of interim and limited base rate relief and the $36 million favorable impact of weather, partially offset by the $41 million unfavorable impact of retail customer growth and usage. The interim and limited base rate relief was approved by the FPSC effective July 1, 2009, as discussed in Note 7C. Of the $79 million interim and limited base rate relief, $7 million related to interim rate relief, which was in effect for only 2009, and $72 million related to limited rate relief, which will continue in accordance with the base rate proceeding with an annual revenue requirement of $132 million. The favorable impact of weather was primarily driven by 14 percent higher heating degree days than 2008 and 6 percent higher cooling degree days than 2008. Heating degree days were 4 percent lower than normal in 2009 and 16 percent lower than normal in 2008. In addition to lower average usage per customer, PEF's average number of customers for 2009, compared to 2008, decreased a net 8,000 customers and had no change in customers for 2008, compared to 2007.

PEF's clause-recoverable regulatory returns were $87 million and $11 million for 2009 and 2008, respectively. The $76 million higher revenues related to nuclear cost recovery and ECRC assets of $61 million and $15 million, respectively. As a result of an FPSC regulatory order effective in January 2009, PEF is allowed to earn returns on certain costs related to nuclear construction, as discussed in Note 7C. We anticipate higher returns on ECRC assets in 2010 due to placing approximately $790 million of Clean Air Interstate Rule (CAIR) projects into service in late 2009. However, we do not anticipate a significant change in returns on nuclear cost-recovery assets in 2010 related to Levy.

PEF's total retail base revenues were $1.378 billion and $1.322 billion for 2008 and 2007, respectively. The $56 million increase was primarily due to $90 million of base rate increases, partially offset by the $32 million impact of unfavorable net retail customer growth and usage. The increase in base rates was due to $53 million from Hines 4 being placed in service and the $37 million transfer of Hines 2 cost recovery from the fuel clause to base rates. These base rate changes occurred in accordance with PEF's 2005 base rate settlement agreement.

PEF's wholesale base revenues of $197 million and $148 million for 2008 and 2007, respectively, increased $49 million. The increase was primarily due to several new and amended contracts.

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

(in millions of kWh)

Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**19,399**	0.4	19,328	(2.9)	19,912
Commercial	**11,884**	(2.1)	12,139	(0.4)	12,183
Industrial	**3,285**	(13.2)	3,786	(0.9)	3,820
Governmental	**3,256**	(1.4)	3,302	(1.9)	3,367
Unbilled	**131**	–	(99)	–	(6)
Total retail kWh sales	**37,955**	(1.3)	38,456	(2.1)	39,276
Wholesale	**3,835**	(43.1)	6,734	11.8	6,024
Total kWh sales	**41,790**	(7.5)	45,190	(0.2)	45,300

Wholesale base revenues increased in 2009, despite decreased wholesale kWh sales in 2009, primarily due to committed capacity revenues. The wholesale kWh sales decreased primarily due to market conditions in which wholesale customers fulfilled a portion of their system requirements from other sources. Many of the new and amended capacity contracts entered into in 2008 expired by the end of 2009. Given the current economic conditions discussed below, PEF does not believe it is likely to replace these wholesale contracts in 2010.

Retail base revenues increased in 2009, despite a decrease in kWh sales for the same period, primarily due to the impact of interim and limited base rate relief approved by the FPSC in 2009 (See Note 7C). Retail base revenues increased in 2008, despite a decrease in kWh sales for the same period, primarily due to an increase in base rates in accordance with PEF's 2005 base rate settlement agreement, as previously discussed.

The economic conditions and general housing downturn in the United States has continued to contribute to a slowdown in customer growth and usage in PEF's service territory resulting in a 1.3 percent decrease in retail kWh sales for 2009, compared to 2008, and a 2.1 percent decrease for 2008, compared to 2007. The impact of the general housing downturn was especially severe in several states, including Florida. Additionally, we believe the current economic conditions have impacted our wholesale customers' usage. We cannot predict how long these economic conditions may last or the extent to which revenues may be impacted. In the future, PEF's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $2.754 billion in 2009, which represents a $126 million increase compared to 2008. Fuel used in electric generation increased $397 million to $2.072 billion compared to 2008. This increase was primarily due to higher deferred fuel expense of $467 million driven by the implementation of new fuel rates, partially offset by decreased current year fuel costs of $70 million. The decrease in current year fuel costs was primarily due to lower system requirements. Purchased power expense decreased $271 million compared to the same period in 2008, primarily due to $164 million lower interchange costs and a decrease in the recovery of deferred capacity costs of $91 million, both resulting from lower system requirements.

Fuel and purchased power expenses were $2.628 billion in 2008, which represents an $18 million decrease compared to 2007. Fuel used in electric generation decreased $89 million to $1.675 billion primarily due to a $381 million decrease in deferred fuel expense, partially offset by increased fuel costs of $293 million. The decrease in deferred fuel expense was primarily due to the regulatory approval to lower the fuel factor for customers effective January 2008 as a result of over-recovery of fuel costs in the prior year. With the increase in fuel prices experienced in 2008, PEF successfully sought a mid-course fuel correction, but the revised fuel factors were not effective until August 2008. The increase in fuel costs was primarily due to increased fuel prices and a change in generation mix. Purchased power expense increased $71 million to $953 million compared to 2007. This increase was primarily due to increased purchases of $37 million as a result of higher fuel costs and an increase in the recovery of deferred capacity costs of $34 million.

Operation and Maintenance

O&M expense was $839 million in 2009, which represents a $26 million increase compared to 2008. The increase was primarily due to $63 million higher ECRC and energy conservation cost recovery clause (ECCR) costs primarily due to an increase in current year rates for recovery of emission allowances, higher pension costs of $24 million and higher nuclear plant outage and maintenance costs of $14 million, partially offset by lower storm cost recovery of $66 million due to the surcharge that ended in July 2008 and the impact of a change in our earned vacation policy of $11 million. The ECRC and ECCR expenses and replenishment of storm damage reserve are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Pension costs are higher due to a $20 million pension credit in the prior year. Substantially all of 2009's pension expense has been deferred in accordance with an FPSC order (See Note 7C). In the aggregate, O&M expenses recoverable through base rates increased $25 million compared to the same period in 2008.

O&M expense was $813 million in 2008, which represents a $21 million decrease compared to 2007. The decrease was primarily due to $24 million lower ECRC costs due to a decrease in the rates resulting from over-recovery, $12 million lower employee benefit costs primarily due to the 2007 impact from changes in stock-based compensation plans and $12 million lower sales and use tax audit adjustment, partially offset by $19 million related to storm damage reserves replenishment surcharge in effect August 2007 through July 2008 in accordance with a regulatory order, and $11 million higher plant outage and maintenance costs. The ECRC and replenishment of storm damage reserves expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates decreased $19 million compared to the same period in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $502 million for 2009, which represented an increase of $196 million compared to 2008, primarily due to higher nuclear cost-recovery amortization of $155 million (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $31 million compared to 2008, primarily due to depreciable asset base increases.

Depreciation, amortization and accretion expense was $306 million for 2008, which represented a decrease of $60 million compared to 2007, primarily due to $75 million lower amortization of unrecovered storm restoration costs and a $7 million write-off in 2007 of leasehold improvements primarily related to vacated office space, partially offset by the $20 million impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a storm-recovery surcharge and, therefore, had no material impact on earnings (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $13 million compared to 2007, primarily due to depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $347 million, $309 million and $309 million in 2009, 2008 and 2007, respectively. The $38 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts and franchise taxes due to higher operating revenues. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expense was an expense of $7 million in 2009, income of $5 million in 2008 and an expense of $8 million in 2007. The $7 million expense in 2009 and the $8 million expense in 2007 were primarily due to regulatory disallowances of fuel costs (See Note 7C). The $5 million income in 2008 was primarily due to gain on land sales.

Total Other Income, Net

Total other income, net was $100 million for 2009, which represents a $6 million increase compared to 2008. This increase was primarily due to the $16 million of investment gains on certain employee benefit trusts resulting from improved market conditions, partially offset by $5 million lower interest income resulting from lower short-term investment balances and $4 million unfavorable AFUDC equity related to eligible construction project costs, primarily due to placing the repowered Bartow Plant into service in 2009.

Total other income, net was $94 million for 2008, which represents a $46 million increase compared to 2007. This increase was primarily due to $54 million favorable AFUDC equity related to eligible construction project costs, partially offset by $11 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

Total Interest Charges, Net

Total interest charges, net was $231 million in 2009, which represents an increase of $23 million compared to 2008. The increase in interest charges was primarily due to higher interest as a result of higher average debt outstanding.

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

Income Tax Expense

Income tax expense was $209 million, $181 million and $144 million in 2009, 2008 and 2007, respectively. The $28 million income tax expense increase in 2009 compared to 2008 was primarily due to the $40 million impact of higher pre-tax income compared to the prior year, partially offset by the $11 million impact of the favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT fund to the qualified NDT fund. The $37 million income tax expense increase in 2008 compared to 2007 was primarily due to the $40 million impact of higher pre-tax income compared to 2007, $6 million benefit related to the closure of certain federal tax years and positions in 2007, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's 2005 base rate settlement agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense.

Corporate and Other

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

(in millions)	2009	Change	2008	Change	2007
Other interest expense	**$(253)**	$(30)	$(223)	$(18)	$(205)
Other income tax benefit	**87**	1	86	(19)	105
Other income (expense)	**12**	13	(1)	17	(18)
Ongoing Earnings	**(154)**	(16)	(138)	(20)	(118)
CVO mark-to-market	**19**	19	–	2	(2)
Valuation allowance and related net operating loss carry forward	**–**	3	(3)	(3)	–
Impairment[a]	**(2)**	(2)	–	–	–
Discontinued operations attributable to controlling interests, net of tax	**(79)**	(136)	57	246	(189)
Net loss attributable to controlling interests	**(216)**	(132)	(84)	225	(309)

[a] Calculated using assumed tax rate of 40 percent.

OTHER INTEREST EXPENSE

Other interest expense was $253 million, $223 million and $205 million for 2009, 2008 and 2007, respectively. The $30 million increase for 2009 compared to 2008 was primarily due to higher average debt outstanding at the Parent. The $18 million increase for 2008 compared to 2007 was primarily due to a $6 million 2007 benefit related to the closure of certain federal tax years and positions and a decrease in the interest allocated to discontinued operations. The decrease in interest allocated to discontinued operations resulted from the allocations of interest expense in early 2007 to operations that were sold later in 2007. An immaterial amount and $13 million of interest expense were allocated to discontinued operations for 2008 and 2007, respectively. No interest expense was allocated to discontinued operations in 2009.

OTHER INCOME TAX BENEFIT

Other income tax benefit was $87 million, $86 million and $105 million for 2009, 2008 and 2007, respectively. The $1 million increase for 2009 compared to 2008 was primarily due to higher pre-tax expenses, partially offset by the unfavorable impact at the Corporate level resulting from the deductions taken by the Utilities related to NDT funds (See "Progress Energy Carolinas – Income Tax Expense" and "Progress Energy Florida – Income Tax Expense"). The $19 million decrease for 2008 compared to 2007 was primarily due to the 2007 benefit related to the closure of certain federal tax years and positions.

OTHER INCOME (EXPENSE)

Other income (expense) was $12 million income, $1 million expense and $18 million expense for 2009, 2008 and 2007, respectively. The $13 million change for 2009 compared to 2008 was primarily due to investment gains on certain employee benefit trusts resulting from improved financial market conditions. The $17 million change for 2008 compared to 2007 was primarily due to $15 million decreased indirect corporate overhead due to divestitures completed in 2007 and $12 million decreased legal expenses, partially offset by $8 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

CVO MARK-TO-MARKET

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate (See Note 15). The CVOs had a fair value of $15 million at December 31, 2009, and $34 million at December 31, 2008 and 2007. Progress Energy recorded unrealized gains of $19 million for 2009 and unrealized losses of $2 million for 2007, to record the changes in fair value of the CVOs, which had average unit prices of $0.16 at December 31, 2009 and $0.35 at December 31, 2008 and 2007.

VALUATION ALLOWANCE AND RELATED NET OPERATING LOSS CARRY FORWARD

We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures, Inc.'s (PVI) nonregulated generation facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate.

IMPAIRMENT

In 2009, Progress Energy recorded impairments of certain investments of our Affordable Housing portfolio.

DISCONTINUED OPERATIONS ATTRIBUTABLE TO CONTROLLING INTERESTS, NET OF TAX

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. See Note 3 for additional information related to discontinued operations.

In 2009, we recognized $79 million of expense from discontinued operations attributable to controlling interests, net of tax, which was primarily due to a jury delivering a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates previously engaged in coal-based solid synthetic fuels operations. As a result, we recorded an after-tax charge of $74 million to discontinued operations in 2009, which was net of a previously recorded indemnification liability. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information.

During 2008 we recognized $57 million of income from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $49 million after-tax gains on sales of our coal terminals and docks in West Virginia and Kentucky (Terminals) and our remaining coal mining businesses.

In 2007, we recognized $189 million of expense from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $283 million net losses related to the exit of the Competitive Commercial Operations (CCO) business, partially offset by $83 million net earnings related to the Terminals and Synthetic Fuels businesses. The net losses from the CCO business were primarily due to the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to de-designated natural gas hedges. We had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Impact of Utility Regulation

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

Our conclusion that we meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our and the Utilities' financial position and results of operations. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by actions of our regulators, competitive forces and restructuring in the electric utility industry. State regulators may not allow the Utilities to increase future retail rates required to recover their operating costs or provide an adequate return on investment, or in the manner requested. State regulators may also seek to reduce or freeze retail rates. Such events occurring over a sustained period could result in the Utilities no longer meeting the criteria for the continued application of GAAP for regulated operations. In the event that GAAP for regulated operations no longer applies to one or both of the Utilities, we are subject to the risk that regulatory assets and liabilities would be eliminated and utility plant assets may be impaired, unless an appropriate recovery mechanism was provided. Additionally, our financial condition, cash flows and results of operations may be adversely impacted. See Note 7 for additional information related to the impact of utility regulation on our operations.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. If an impairment indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred. The carrying value of our total utility plant, net at December 31, 2009 and 2008, was $19.733 billion and $18.293 billion, respectively.

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

Asset Retirement Obligations

Asset Retirement Obligations (AROs) represent legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability.

AROs have no impact on our income as the effects are offset by the establishment of regulatory assets and regulatory liabilities.

Our total AROs at December 31, 2009, were $1.170 billion. We calculated the present value of our AROs based on estimates which are dependent on subjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 95 percent of Progress Energy's total AROs at December 31, 2009. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized.

PEC obtained updated cost studies for its nuclear plants in 2009, using 2009 cost factors. If the site-specific cost estimates increased by 10 percent, PEC's AROs would have increased by $77 million. If the inflation adjustment increased 25 basis points, PEC's AROs would have increased by $169 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEC's AROs by $56 million.

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

Goodwill

As discussed in Note 8, goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. The carrying amounts of goodwill at December 31, 2009 and 2008, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. We perform our annual impairment tests as of April 1 each year. During the second quarter of 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired. If the fair value of PEC had been lower by 10 percent and the fair value of PEF had been lower by 7.5 percent, there still would be no impact on the reported value of their goodwill.

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

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

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

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

As an overall test of the reasonableness of the estimated fair values of the utility segments, we compared their combined fair value estimate to Progress Energy's market capitalization as of April 1, 2009. The analysis confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

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

Unbilled Revenue

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. At December 31, 2009 and 2008, amounts recorded as receivables on the Consolidated Balance Sheets related to unbilled revenues were $193 million and $182 million, respectively.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 14, deferred income tax assets and liabilities represent the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax-planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material. In accordance with GAAP, the uncertainty and judgment involved in the determination and filing of income taxes are accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required: recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority.

Pension Costs

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

Due to a slight decrease in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate to calculate the present value of future benefit payments, we decreased the discount rate to 6.00% at December 31, 2009, from 6.30% at December 31, 2008, which will increase 2010 pension costs, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Consistent with general market conditions, our plan assets performed well in 2009 with returns of approximately 23%. That positive asset performance will result in decreased pension costs in 2010, all other factors remaining constant. In addition, contributions to pension plan assets in late 2009 and 2010 will result in decreased pension costs in 2010 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2010 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2010 will be $80 million to $90 million, compared with $107 million (before the $34 million deferral; see Notes 7C and 16A) recognized in 2009.

We have pension plan assets with a fair value of approximately $1.7 billion at December 31, 2009. Our expected rate of return on pension plan assets is 8.75%. The expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2009, we lowered the expected rate of return from the previously used 9.00%, due primarily to the uncertainties resulting from the severe capital market deterioration in 2008. A 25 basis point change in the expected rate of return for 2009 would have changed 2009 pension costs by approximately $4 million.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is the method selected to determine the market-related value of assets, i.e., the asset value to which the 8.75% expected long-term rate of return is applied. Entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. We have historically used a five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

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

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

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.3 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures. During 2009, PEC paid a dividend of $200 million to the Parent and PEF received equity contributions of $620 million from the Parent. PEC and PEF expect to pay dividends to the Parent in 2010. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, and/or limited ongoing sales of common stock from our Progress Energy Investor Plus Plan (IPP), employee benefit and stock option plans are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2010. For the fiscal year 2010, we plan, subject to market conditions, to realize up to $500 million from the sale of stock through ongoing equity sales. As discussed further in "Credit Rating Matters," our ability to access the capital markets on favorable terms may be negatively impacted by recent, and potentially future, rating actions.

We have 16 financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as backups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009, the Parent had no outstanding borrowings under its credit facility, an outstanding commercial paper balance of $140 million and had issued $37 million of letters of credit, which were supported by the revolving credit facility. At December 31, 2009, PEC and PEF had no outstanding commercial paper. Based on these outstanding amounts at December 31, 2009, there was $1.853 billion available for additional borrowings. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

Borrowings under our revolving credit agreement (RCA) during 2008, which were repaid during 2009, coupled with commercial paper, long-term debt and equity issuances in 2009, provided liquidity during a period of uncertain financial market conditions. We will continue to monitor the credit markets to maintain an appropriate level of liquidity.

At December 31, 2009, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2009, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, each sum of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps was in a net mark-to-market asset position. See Note 17B for additional information with regard to our interest rate derivatives.

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

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below.

Historical for 2009 as Compared to 2008 and 2008 as Compared to 2007

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. Net cash provided by operating activities for the three years ended December 31, 2009, 2008 and 2007, was $2.271 billion, $1.218 billion and $1.252 billion, respectively.

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.053 billion increase in operating cash flow was primarily due to a $623 million increase in the recovery of deferred fuel costs due to higher fuel rates and $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $200 million net refunds of cash collateral in 2009. These impacts were partially offset by $221 million of pension and other benefits contributions made in 2009.

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $34 million decrease in operating cash flow was primarily due to a $450 million decrease in the recovery of fuel costs due to the 2008 under-recovery driven by rising fuel costs, compared to an over-recovery of fuel costs during the corresponding period in 2007; $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $55 million in net refunds of cash collateral in 2007, primarily at PEF; and a $226 million increase in inventory purchases, primarily coal, driven by higher prices. These impacts were partially offset by a $419 million increase from accounts receivable, primarily related to our divested CCO operations and former synthetic fuels businesses; the $347 million payment made in 2007 to exit the contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO (the Georgia contracts) (See Note 3C); a $117 million increase from accounts payable; and a $106 million increase from income taxes, net. The increase from accounts receivable was primarily driven by the settlement of $234 million of derivative receivables related to derivative contracts for our former synthetic fuels businesses (See Note 17A). The increase from income taxes, net was largely due to $252 million in income tax payments made in 2007 related to the sale of natural gas drilling and production business, partially offset by income tax impacts at PEC. The change in accounts payable was primarily related to our divested operations.

In 2009, 2008 and 2007, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2009, 2008 and 2007, was $2.532 billion, $2.541 billion and $1.457 billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.488 billion and $2.534 billion in 2009 and 2008, respectively, or approximately 100 percent of consolidated capital expenditures in both 2009 and 2008. Capital expenditures at the Utilities are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1 million in 2009 and $72 million in 2008, cash used in investing activities decreased by $80 million. The decrease in 2009 was primarily due to a $24 million decrease in gross property additions at the Utilities, primarily due to lower spending for environmental compliance projects and the completion of PEF's Bartow Plant repowering project in 2009; a $22 million decrease in nuclear fuel additions; and a $20 million decrease in net purchases of available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $72 million in 2008 and $675 million in 2007, cash used in investing activities increased by $481 million. The increase in 2008 was primarily due to a $341 million increase in gross property additions at the Utilities, primarily at PEF, and a $95 million decrease in net purchases of available-for-sale securities and other investments. The increase in capital expenditures for utility property additions at PEF was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility.

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

During 2007, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $615 million from the sale of PVI's CCO generation assets (See Note 3C), working capital adjustments related to the sale of natural gas drilling and production business, and the sale of poles at Progress Telecommunications Corporation.

FINANCING ACTIVITIES

Net cash provided by financing activities for the three years ended December 31, 2009, 2008 and 2007, was $806 million, $1.248 billion and $195 million, respectively. See Note 11 for details of debt and credit facilities.

The decrease in net cash provided by financing activities for 2009 compared to 2008 is primarily due to a $2.077 billion net decrease in short-term indebtedness, primarily driven by commercial paper repayments and the Parent's repayment of borrowings outstanding under its RCA; partially offset by a $491 million increase in proceeds from the issuance of common stock, primarily related to the Parent's January 2009 common stock offering; a $481 million increase in net proceeds from long-term debt issuances due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $1.500 billion issuance and PEC's $325 million issuance in 2008; a $477 million decrease in payments at maturity of long-term debt; and a $118 million decrease in net payments on short-term debt with original maturities greater than 90 days.

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

Our financing activities are described below.

2010

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

- Subsequent to December 31, 2009, the Parent has issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million. On February 3, 2009, the Parent used $100 million of the proceeds to reduce its $600 million RCA balance outstanding at December 31, 2008, and the remainder was used for general corporate purposes.
- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.
- On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.
- On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.
- On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to pre-fund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.
- During 2009, we repaid the November 2008 $600 million borrowing under our RCA.
- Progress Energy issued approximately 3.1 million shares of common stock resulting in approximately $100 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.5 million shares for proceeds of approximately $100 million issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the IPP. For 2009, the dividends paid on common stock were approximately $693 million.

2008

- On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.
- On March 12, 2008, PEC and PEF amended their RCAs with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA is now scheduled to expire on June 28, 2011, and PEF's RCA is now scheduled to expire on March 28, 2011 (See "Credit Facilities and Registration Statements").
- On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.
- On April 14, 2008, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").
- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.
- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.
- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. The borrowing was repaid during 2009.

- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the 401(k) and the IPP. For 2008, the dividends paid on common stock were approximately $642 million.

2007

- On July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings.
- On August 15, 2007, due to extreme volatility in the commercial paper market, Progress Energy borrowed $400 million under its $1.13 billion RCA to repay outstanding commercial paper. On October 17, 2007, Progress Energy used $200 million of commercial paper proceeds to repay a portion of the amount borrowed under the RCA. On December 17, 2007, Progress Energy used $200 million of available cash on hand to repay the remaining amount borrowed under the RCA.
- On August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.
- On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.
- On December 10, 2007, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $35 million of its 6.75% Medium-Term Notes with available cash on hand.
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $151 million in proceeds from its IPP and its equity incentive plans. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million issued for the IPP. For 2007, the dividends paid on common stock were approximately $627 million.

Future Liquidity and Capital Resources

Please review "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At December 31, 2009, we have carried forward $712 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

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

We issue commercial paper to meet short-term liquidity needs. As a result of financial and economic conditions in 2008 and 2009, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. The Parent borrowed $600 million under its RCA in November 2008 and repaid the outstanding balance during 2009 with proceeds from the January 2009 equity issuance, cash on hand and proceeds from commercial paper borrowings. If liquidity conditions deteriorate again and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our RCA, issuing short-term notes, issuing long-term debt and/or issuing equity. If our short-term credit ratings are downgraded below Tier 2

(A-2/P-2/F2), we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets could be negatively impacted. In the event of a downgrade of our senior unsecured credit ratings, our credit facility fees and borrowing rates under our RCAs could increase. We do not expect an increase in such RCA fees to be material. See "Credit Rating Matters" for further discussion regarding credit ratings.

The current RCAs for the Parent, PEC and PEF expire in May 2012, June 2011 and March 2011, respectively. We are currently evaluating options for addressing these upcoming expirations. In the event we enter into new credit facilities, we cannot predict the terms, prices, durations or participants in such facilities.

Progress Energy and its subsidiaries have approximately $12.051 billion in outstanding long-term debt. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may move our tax-exempt bonds below A3/A-. PEC's senior secured debt ratings are currently A1 by Moody's Investors Service, Inc. (Moody's) and A-/Watch Negative by Standard and Poor's Rating Services (S&P). PEF's senior secured debt ratings are currently A1/Watch Negative by Moody's and A-/Watch Negative by S&P. In the event of a one notch downgrade of PEC's and/or PEF's senior secured debt rating by S&P, the ratings of both utilities' tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a one notch downgrade by Moody's, PEC's and PEF's tax-exempt bonds will continue to be rated above A3. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $120 million of contributions directly to pension plan assets in 2010 (See Note 16).

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under "Other Matters – Increasing Energy Demand" will require the Utilities to make significant capital investments. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and/or common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation. As discussed in "Other Matters – Nuclear – Potential New Construction," PEF expects its capital expenditures for the Levy project will be significantly less in the near term than previously planned in light of a regulatory schedule shift and other factors.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. At February 19, 2010, we had posted approximately $168 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2010 and 2011. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. In addition, as discussed in "Credit Rating Matters," if our credit ratings are downgraded, we may have to post additional cash collateral for derivatives in a liability position.

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

At December 31, 2009, the current portion of our long-term debt was $406 million. On January 15, 2010, we funded the $100 million Series A Floating Rate Notes maturity with proceeds from the Parent's November 2009 $950 million long-term debt issuance, and we expect to fund the remaining $306 million with a combination of cash from operations,commercial paper borrowings and long-term debt.

See "Credit Rating Matters" for information regarding recent rating actions.

REGULATORY MATTERS AND RECOVERY OF COSTS

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

As discussed further in Note 7 and in "Other Matters – Regulatory Environment," the North Carolina, South Carolina and Florida legislatures passed energy legislation that became law in recent years. These laws may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and energy efficiency.

PEC Cost-Recovery Clause

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On June 19, 2009, the SCPSC approved a settlement agreement filed jointly by PEC and the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million, which went into effect July 1, 2009.

On June 4, 2009, PEC filed with the North Carolina Utilities Commission (NCUC) for a decrease in the fuel rate charged to its North Carolina ratepayers. The filing was updated on August 17, 2009. PEC asked the NCUC to approve a $14 million decrease in the fuel rates driven by declining fuel prices, which went into effect December 1, 2009. At December 31, 2009, PEC's North Carolina deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010.

PEC Other Matters

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

As discussed in Note 7 and in "Other Matters – Environmental Matters," on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. We intend to continue to depreciate the three coal-fired units at their current depreciation rate until PEC's next depreciation study. PEC projects that the generating facility would be in service by January 2013. The filed estimate of capital expenditures, net of AFUDC–borrowed funds for the new generating facility is approximately $800 million. PEC modified its Clean Smokestacks Act compliance plan for the change in fuel source and removed retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC, which decreased estimated capital expenditures to meet the Clean Smokestacks Act emission targets by 2013 to $1.1 billion from $1.4 billion. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

In accordance with the October 2009 NCUC order, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. We intend to continue to depreciate the coal-fired units at their current depreciation rate until PEC's next depreciation study. On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. The filed estimate of capital expenditures, net of AFUDC–borrowed funds for the new generating facility is approximately $600 million. PEC projects that the generating facility would be in service by late 2013 or early 2014.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. The interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual O&M costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options.

PEF Cost-Recovery Clauses

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel-purchasing strategies and lower fuel prices. The approval reduced customers' fuel charges starting with the first billing cycle of April 2009.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. On October 23, 2009, PEF filed a $3 million cost adjustment with the FPSC, which reduced the capacity cost-recovery clause (CCRC) rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

In addition, on August 28, 2009 and as updated on October 27, 2009, PEF filed a request to increase the ECRC residential rate. Also, on September 14, 2009, PEF filed a request to increase the ECCR residential rate. The FPSC approved a combined $37 million increase in PEF's ECRC and ECCR clauses on November 2, 2009, to be effective January 1, 2010.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve its integrated strategy to address compliance with CAIR, the Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) through the ECRC (See "Other Matters – Environmental Matters" for discussion regarding the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the CCRC. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs through the CCRC, and found that PEF's project management, contracting, and oversight controls were reasonable and prudent. As discussed in Note 7, on October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced customers' nuclear cost-recovery charge starting with the first billing cycle of April 2009.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million through the nuclear cost-recovery clause of the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt and equity issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2009.

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

	Actual	Forecasted		
(in millions)	**2009**	2010	2011	2012
Regulated capital expenditures	**$1,995**	$2,160	$2,120	$1,810
Nuclear fuel expenditures	**200**	230	300	260
AFUDC-borrowed funds	**(37)**	(30)	(40)	(40)
Other capital expenditures	**7**	30	30	30
Total before potential nuclear construction	**2,165**	2,390	2,410	2,060
Potential nuclear construction[a]	**291**	100 – 150	60 – 70	60 – 70
Total	**$2,456**	$2,490 – 2,540	$2,470 – 2,480	$2,120 – 2,130

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

Regulated capital expenditures for 2010, 2011 and 2012 in the previous table include approximately $130 million, $40 million and $100 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2010, 2011 and 2012 include $20 million, $40 million and $50 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2010 and 2012 include $110 million and $50 million, respectively, at PEF. No environmental compliance capital expenditures are forecasted for PEF in 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

Potential nuclear construction expenditures, which are primarily for PEF's Levy, include development, licensing and equipment. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement (See discussion under "Other Matters – Nuclear – Potential

New Construction"). The forecasted capital expenditures presented in the previous table reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and/or exit costs cannot be determined at this time and, accordingly, are not included in the previous table. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions. Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

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

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

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

All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities. See Note 11 for additional discussion of our credit facilities.

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

All of the credit facilities include defined maximum total debt-to-total capital ratio (leverage) covenants, which we were in compliance with at December 31, 2009. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2009, the calculated ratios pursuant to the terms of the agreements are as disclosed in Note 11.

(in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
2009					
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$–**	**$177**	**$1,853**
2008					
Parent	Five-year (expiring 5/3/12)	$1,130	$600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$600	$580	$850

[a] The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had a total amount of $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various securities, including senior debt securities, junior subordinated debentures, common stock, preferred stock, stock purchase contracts, stock purchase units, and trust preferred securities and guarantees.

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

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

Both PEC and PEF can issue first mortgage bonds under their respective first mortgage bond indentures based on property additions, retirements of first mortgage bonds and the deposit of cash, provided that adjusted net earnings are at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2009, PEC and PEF could issue up to approximately $6.0 billion and $2.6 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. At December 31, 2009, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 4.9 times and 3.4 times, respectively.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

	2009	2008
Total equity	**42.3%**	41.9%
Preferred stock	**0.4%**	0.5%
Total debt	**57.3%**	57.6%

CREDIT RATING MATTERS

At February 22, 2010, the major credit rating agencies rated our securities as follows:

Long-Term Ratings	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Parent			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
PEC			
Outlook/Watch	Stable	Watch Negative[b]	Stable
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	BBB+
PEF			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Watch Negative[c]
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Preferred stock	Baa2	BBB-	BBB+
Florida Progress Corporation (FPC) Capital I			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Watch Negative[c]
Quarterly Income Preferred Securities[d]	Baa2	BBB-	BBB+
Short-Term Ratings			
Parent			
Watch	Watch Negative[a]	N/A	N/A
Commercial paper	P-2	A-2	F2
PEC			
Watch	N/A	N/A	N/A
Commercial paper	P-2	A-2	F1
PEF			
Watch	N/A	N/A	Watch Negative[c]
Commercial paper	P-2	A-2	F1

(a) On January 19, 2010, Moody's placed these ratings on review for possible downgrade.
(b) On January 14, 2010, S&P placed these ratings on CreditWatch Negative.
(c) On January 12, 2010, Fitch placed these ratings on Rating Watch Negative.
(d) Guaranteed by the Parent and FPC.

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

On August 3, 2009, Moody's raised the senior secured debt rating of both PEC and PEF to A1 from A2 as a result of Moody's reevaluating its notching criteria for investment-grade regulated utilities to reflect the historical lower default rates for regulated utilities than for non-financial, non-utility corporate issuers.

On January 12, 2010, Fitch placed ratings of PEF and FPC Capital I on Rating Watch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Fitch cited lower cash flow expectations and increased regulatory risk as drivers for the rating action.

On January 14, 2010, S&P placed ratings of Progress Energy, Inc. and its subsidiaries, including PEC, PEF, FPC Capital I and Florida Progress Corp., on CreditWatch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. At the same time, S&P affirmed the A-2 short-term ratings on Progress Energy, Inc., PEC and PEF.

On January 19, 2010, Moody's placed the long-term ratings of Progress Energy, Inc. and PEF on review for possible downgrade as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Moody's also placed the short-term rating for commercial paper of Progress Energy, Inc. on review for possible downgrade. At the same time, Moody's affirmed the ratings and stable outlook of PEC.

As noted above, the three rating agencies cited increased regulatory risk and PEF's rate case outcome as the key driver of the ratings actions. Credit rating changes could be made after the agencies have completed their reviews of PEF's rate order and our response to the decision.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customers' future energy needs.

As discussed in Note 17C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

On January 22, 2010, Fitch lowered the rating on PEC's, PEF's and FPC Capital I's preferred securities to BBB+ from A- as a result of the implementation of Fitch's revised guidelines for rating preferred stock and hybrid securities.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2009, we have issued $406 million of guarantees for future financial or performance assurance. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At December 31, 2009, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

Market Risk and Derivatives

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

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented in the following table are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs.

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2009, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 11)	$12,515	$406	$1,950	$1,125	$9,034
Interest payments on long-term debt[b]	10,077	707	1,289	1,073	7,008
Capital lease obligations[c] (See Note 22B)	484	34	67	74	309
Operating leases[c] (See Note 22B)	1,430	35	83	181	1,131
Fuel and purchased power[d] (See Note 22A)	24,070	3,092	5,202	3,923	11,853
Other purchase obligations[e] (See Note 22A)	9,749	1,872	3,288	2,883	1,706
Minimum pension funding requirements[f]	794	74	353	229	138
Other postretirement benefits[g] (See Note 16A)	397	34	73	79	211
Uncertain tax positions[h] (See Note 14)	–	–	–	–	–
Other commitments[i]	105	13	26	26	40
Total	$59,621	$6,267	$12,331	$9,593	$31,430

[a] Our maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

[b] Interest payments on long-term debt are based on the interest rate effective at December 31, 2009.

[c] Amounts include certain related executory cost commitments.

[d] Essentially all fuel and certain purchased power costs incurred by the Utilities are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

[e] Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. The contractual obligations presented are in accordance with the existing terms of the EPC agreement, which assumes the original construction schedule and 100 percent ownership by PEF. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction.") We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in this table.

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

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

[h] Uncertain tax positions of $160 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements.

[i] By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

Regulatory Environment

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

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

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency and renewable energy, including $3.4 billion in Smart Grid technology development grants; $615 million for Smart Grid storage, monitoring and technology viability; $6.3 billion for energy-efficiency and conservation grants; and $2 billion in tax credits for the purchase of plug-in electric vehicles. In August 2009, we submitted our application to the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our investment in Smart Grid-related technologies in the Carolinas and Florida. On October 27, 2009, the DOE notified us of our selection for Smart Grid award negotiations. We are now awaiting further questions and comments from the DOE on our Smart Grid application. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the incentive programs. Also, the Obama administration has announced a goal of encouraging investment in transmission and promoting renewable resources while also pricing GHG emissions and setting a federal requirement for renewable energy.

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

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

On July 31, 2009, the governor of North Carolina signed into law a bill that includes three key provisions that may impact PEC. First, the legislation accelerates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal unit at that specific site. Pursuant to the legislation, PEC requested and received approval from the NCUC to pursue construction of a new 950-MW natural gas plant (see further discussion in Note 7B and "Other Matters – Environmental Matters"). Second, a recovery mechanism is provided for utilities if they invest in zero emissions renewable energy facilities within the next five years. Finally, the legislation changes the state's Dam Safety Act such that dams at utility coal-fired power plants, including dams for ash ponds, will be subject to the Act's applicable provisions, including state inspection, as of January 1, 2010.

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

On July 13, 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of GHGs for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions. To date, the FDEP has held three rulemaking workshops on the GHG cap-and-trade rulemaking. Rulemaking is expected to continue through 2010, and the rule requires legislative ratification before implementation.

The executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from onsite renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter.

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

North Carolina energy law enacted in 2007 includes provisions for a North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), expansion of the definition of the traditional fuel clause and recovery of the costs of new DSM and energy-efficiency programs through an annual DSM clause. On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's 2007 energy law. The rules include filing requirements regarding NC REPS compliance and inclusion in the Utility's integrated resource plan. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the NC REPS clause will be set based on projected costs with true-up provisions. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results.

Energy Demand

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

We are actively pursuing expansion of our DSM, energy-efficiency and conservation programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. We provide our residential customers with home energy audits and offer energy-efficiency programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet Web site with online calculators, programs and efficiency tips, to help them reduce their energy use.

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

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The coal-fired units will be retired by the end of 2017. PEC has received approval from the NCUC for construction of a 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has requested approval from the NCUC to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C. The facility is projected to be placed in service in late 2013 or early 2014. PEC will continue to operate three coal-fired plants in North Carolina after 2017. PEC has invested more than $2 billion in installing state-of-the-art emission controls at the Roxboro, Mayo and Asheville Plants. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at those sites.

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

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

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

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

Nuclear

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

CR3 is currently undergoing an extended outage for normal refueling and maintenance as well as a project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, finalized repair estimates and replacement power costs, or the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

The NRC operating licenses for PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, if approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

POTENTIAL NEW CONSTRUCTION

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

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed, or accepted for review, the Harris application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. No petitions to intervene have been admitted in the Harris COL application. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019 (See "Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF's requests to change the comprehensive land use plan. On May 29, 2008, the Florida Department of Community Affairs issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

In 2008, PEF submitted filings for two key state approvals. First, on March 11, 2008, PEF filed a Petition for a Determination of Need for Levy with the FPSC. The FPSC issued a final order granting PEF's petition for Levy on August 12, 2008. Second, on June 2, 2008, PEF filed its application for site certification with the FDEP. Certification addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government. On January 12, 2009, the FDEP filed a favorable staff analysis report in advance of certification hearings. The technical proceedings concluded on March 12, 2009, and the administrative law judge issued a recommended order on certification on May 15, 2009. The Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy certification on August 26, 2009.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. On October 6, 2008, the NRC docketed, or accepted for review, the Levy application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On April 20-21, 2009, the Atomic Safety Licensing Board (ASLB) heard oral arguments on whether any of the joint interveners' proposed contentions will be admitted in the Levy COL proceeding. On July 8, 2009, the ASLB issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. We cannot predict the outcome of this matter.

PEF expects a schedule shift for the commercial operation dates of the Levy nuclear units. PEF's initial schedule anticipated the ability to perform certain site work pursuant to a Limited Work Authorization from the NRC prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the Limited Work Authorization scope will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

As discussed below, the schedule shift will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates. The schedule shift will also allow more time for certainty around federal climate change policy, which is currently being debated. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. We still consider Levy as PEF's preferred baseload generation option, taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including public, regulatory and political support; adequate financial cost-recovery mechanisms; customer rate impacts; project feasibility; and availability and terms of capital financing.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. We anticipate amending the EPC agreement due to the schedule shift previously discussed but cannot predict the impact such amendment might have on the project's cost, if any.

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

In 2008, PEF sought and received approval from the FPSC to recover Levy preconstruction and carrying charges of $357 million as well as site selection costs of $38 million through the 2009 CCRC. In 2009, PEF received approval to defer until 2010 the recovery of $198 million of these costs (See Note 7C). On October 16, 2009, the FPSC approved the recovery of $201 million of preconstruction costs, carrying costs and incremental O&M incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with Levy as part of the total $207 million FPSC-approved recovery of nuclear costs through the 2010 CCRC (See Note 7C).

At December 31, 2009, PEF's unrecovered investment in Levy totaled $404 million, of which $358 million is recoverable in retail rates through the Florida nuclear cost-recovery rules, including $296 million of construction work in progress, $274 million of which was reflected as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs and $22 million was reflected as a deferred fuel regulatory asset. The remaining $46 million is apportioned to PEF's wholesale jurisdiction and would be recovered through PEF's wholesale rates. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and/or exit costs that would increase its unrecovered investment. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time.

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

SPENT NUCLEAR FUEL MATTERS

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

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

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

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

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

Environmental Matters

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

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 21A.

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

As discussed in "Other Matters – Regulatory Environment," as of January 1, 2010, dams at utility fossil-fired power plants, including dams for ash ponds, are subject to the North Carolina Dam Safety Act's applicable provisions, including state inspection. Until the state agency responsible for dam safety inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. However, these dams have been subject to periodic third-party inspection in accordance with prior applicable requirements.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary.

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

Only dams rated as "unsatisfactory" would be considered to pose an immediate safety threat, but none of the facilities received an "unsatisfactory" rating. In total, six of PEC's ash pond dams, including one "high hazard potential" impoundment, were rated as "poor" based on the contract inspector's desire to see additional documentation and their evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the recommendations for the active ponds and other recommendations are under way. We are working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, CO_2 and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment installed pursuant to the provisions of CAIR, CAVR and mercury regulations, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. On March 31, 2009, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.4 billion at the time of the filing. As discussed in "Other Matters – Regulatory Environment," North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. The law gives PEC the option to seek certification, construct a new natural gas plant and retire existing coal units, with resulting reduced emissions, in time to comply with the Clean Smokestacks Act's 2013 emission targets. As discussed in Note 7B, on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. PEC projects that the generating facility would be in service by January 2013. On December 1, 2009, PEC filed with the NCUC a plan to retire, no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC modified its Clean Smokestacks Act compliance plan to remove retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC totaling $1.1 billion of capital expenditures to meet the Clean Smokestacks Act emission targets. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expenses increase with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; all other O&M expenses are currently recoverable through base rates.

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

Clean Air Interstate Rule

The CAIR issued by the EPA on March 10, 2005, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR in 2007.

The air quality controls installed to comply with the requirements of the NOx State Implementation Plan Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, largely address the CAIR requirements for our North Carolina units at PEC. PEF met the 2009 phase I requirements for NOx and anticipates meeting the 2010 phase I requirements of CAIR for NOx and SO_2 with a combination of emission reductions generated by in-service emission control equipment and emission allowances. PEF's CR5 equipment was placed in service on December 2, 2009, and PEF's CR4 equipment is expected to be placed in service in 2010.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The EPA informed the D.C. Court of Appeals that development and finalization of a replacement rule could take approximately two years. The outcome of this matter cannot be predicted.

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

Clean Air Mercury Rule

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

Clean Air Visibility Rule

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, on December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

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

Compliance Strategy

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

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

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (See discussion above regarding the vacating of the CAMR and remanding of the CAIR). PEF's April 1, 2009 filing with the FPSC for true-up of final 2008 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.2 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote and Crystal River plants. As discussed in Note 7C, on August 28, 2009, PEF filed for recovery of costs through the ECRC, and the FPSC approved PEF's filing on November 2, 2009. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. The timing and extent of the costs for future projects will depend upon final compliance strategies.

The following table contains information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the table exclude AFUDC.

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act[a]	2002 – 2013	$1,100	$1,050
In-process CAIR projects[b]	2005 – 2010	1,200	1,065
CAVR[c]	– 2017	–	–
Mercury regulation[d]	2006 – 2017	–	4
Total air quality		2,300	2,119
Clean Water Act Section 316(b)[e]		–	–
Total air and water quality		$2,300	$2,119

[a] We are continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.
[b] We are continuing construction of our in-process emission control projects. Additional compliance plans to meet the requirements of a revised rule will be determined upon finalization of the rule. See discussion under "Clean Air Interstate Rule."
[c] As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed. See discussion under "Clean Air Visibility Rule."
[d] Compliance plans to meet the requirements of a revised or new implementing rule will be determined upon finalization of the rule. See discussion under "Clean Air Mercury Rule."
[e] Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."

All environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, which included projects at PEC's Asheville, Lee, Mayo and Roxboro plants, have been placed in service. On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. Additional projects requiring material environmental compliance costs may be implemented in the future to meet compliance requirements.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. As a result of changes in the scope of work related to estimation of costs for compliance with the CAIR and the uncertainty regarding the EPA's further CAIR proceedings, the delisting determination and the CAMR discussed above, PEF is currently unable to estimate certain costs of compliance. However, PEF believes that future costs to comply with new or subsequent rule interpretations could be significant. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when those new regulations are finalized.

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

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force fossil fuel-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In 2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial. In 2009, the D.C. Court of Appeals remanded the EPA's denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

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

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

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

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

On December 8, 2009, the EPA proposed a new 1-hour NAAQS for sulfur dioxide. The current primary NAAQS on a 24-hour average basis and annual average would be eliminated under the proposed rule. A 1-hour standard in the proposed range is a significant increase in the stringency of the standard and it would increase the risk of nonattainment, especially near uncontrolled coal-fired facilities. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants to determine whether changes at those facilities were subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The EPA has undertaken civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities, several of which included reported expenditures in excess of $1.0 billion for retrofit of pollution control equipment. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the unaffiliated utilities may seek recovery of the related costs through rate adjustments or similar mechanisms.

Water Quality

1. General

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

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

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

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) with 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. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

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

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

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

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

Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review those denials of waiver requests. On June 30, 2009, the EPA granted California's waiver request, enabling the state to enforce its GHG emissions standards for new motor vehicles, beginning with the current model year. Additional states may set similar standards as a result of the decision. The impact of this development cannot be predicted.

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

Synthetic Fuels Tax Credits

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

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

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, $1.179 billion of which has been used through December 31, 2009, to offset regular federal income tax liability and $712 million is being carried forward as deferred tax credits.

See Note 22D for additional discussion related to our previous synthetic fuels operations.

Legal

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

New Accounting Standards

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "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.

Interest Rate Risk

As part of our debt portfolio management and daily cash management, we have variable rate long-term debt and typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 9 percent and 18 percent of consolidated debt had variable rates at December 31, 2009 and 2008, respectively.

Based on our variable rate long-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $10 million. Based on our short-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an insignificant annual pre-tax interest expense change.

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

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

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

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

The following tables provide information at December 31, 2009 and 2008, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and Florida Progress-obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual mandatory termination dates for 2010 to 2014 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

(dollars in millions) December 31, 2009	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**	**Fair Value December 31, 2009**
Fixed-rate long-term debt	**$306**	**$1,000**	**$950**	**$825**	**$300**	**$7,864**	**$11,245**	**$12,126**
Average interest rate	**4.53%**	**6.96%**	**6.67%**	**4.96%**	**6.05%**	**6.13%**	**6.12%**	
Variable-rate long-term debt	**$100**	**–**	**–**	**–**	**–**	**$861**	**$961**	**$961**
Average interest rate	**0.73%**	**–**	**–**	**–**	**–**	**0.45%**	**0.48%**	
Debt to affiliated trust[(a)]	**–**	**–**	**–**	**–**	**–**	**$309**	**$309**	**$315**
Interest rate	**–**	**–**	**–**	**–**	**–**	**7.10%**	**7.10%**	
Interest rate forward contracts[(b)]	**$75**	**$150**	**$100**	**–**	**–**	**–**	**$325**	**$19**
Average pay rate	**3.48%**	**4.03%**	**4.07%**	**–**	**–**	**–**	**3.91%**	
Average receive rate	**[(c)]**	**[(c)]**	**[(c)]**	**–**	**–**	**–**	**[(c)]**	

[(a)] FPC Capital I – Quarterly Income Preferred Securities.
[(b)] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[(c)] Rate is 3-month London Inter Bank Offered Rate (LIBOR), which was 0.25% at December 31, 2009.

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

[(a)] FPC Capital I – Quarterly Income Preferred Securities.
[(b)] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[(c)] Rate is 3-month LIBOR, which was 1.43% at December 31, 2008.

During January 2010, Progress Energy entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, including $75 million notional at PEF.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million notional at PEC and $75 million notional at PEF.

At December 31, 2008, Progress Energy had $450 million notional of open forward starting swaps, including $250 million notional at PEC. At December 31, 2007, Progress Energy had $200 million notional of open forward starting swaps, all at PEC.

Marketable Securities Price Risk

The Utilities maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 2009 and 2008, the fair value of these funds was $1.367 billion and $1.089 billion, respectively. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of Florida Progress, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. The CVOs are derivatives and are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively. A hypothetical 10 percent increase in the December 31, 2009 market price would result in a $2 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

Commodity Price Risk

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

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

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2009 and 2008, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

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

ECONOMIC DERIVATIVES

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

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Consolidated Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2009, 2008 and 2007, we recorded a net realized loss of $659 million, a net realized gain of $174 million and a net realized loss of $55 million, respectively.

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

At December 31, 2009, the fair value of PEC's commodity derivative instruments was recorded as a $28 million short-term derivative liability position included in derivative liabilities and a $62 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. PEC had a cash collateral asset included in derivative collateral posted of $7 million and $18 million on the Consolidated Balance Sheet at December 31, 2009 and 2008, respectively.

At December 31, 2009, the fair value of PEF's commodity derivative instruments was recorded as an $11 million short-term derivative asset position included in prepayments and other current assets, a $9 million long-term derivative asset position included in other assets and deferred debits, a $161 million short-term derivative liability position included in current derivative liabilities, and a $174 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in prepayments and other current assets, a $1 million long-term derivative asset position included in other assets and deferred debits, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. PEF's cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheet was $139 million at December 31, 2009, compared to $335 million at December 31, 2008.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2009 and 2008, we had no material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2009, 2008 and 2007.

At December 31, 2009 and 2008, the amount recorded in our accumulated other comprehensive income related to commodity cash flow hedges was not material.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Progress Energy; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America; (3) provide reasonable assurance that receipts and expenditures of Progress Energy are being made only in accordance with authorizations of management and directors of Progress Energy; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Progress Energy's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2009. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit and Corporate Performance Committee (Audit Committee) of the board of directors.

Based on our assessment, management determined that, at December 31, 2009, Progress Energy maintained effective internal control over financial reporting.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the internal control over financial reporting of Progress Energy as of December 31, 2009, as stated in their report.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer

Mark F. Mulhern

Mark F. Mulhern
Senior Vice President and Chief Financial Officer

February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Shareholders of Progress Energy, Inc.:

We have audited the internal control over financial reporting of Progress Energy, Inc. (the Company), as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009, of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements.

Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Shareholders of Progress Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc. and its subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Progress Energy, Inc. and its subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data) Years ended December 31	**2009**	2008	2007
Operating revenues	**$9,885**	$9,167	$9,153
Operating expenses			
Fuel used in electric generation	**3,752**	3,021	3,145
Purchased power	**911**	1,299	1,184
Operation and maintenance	**1,894**	1,820	1,842
Depreciation, amortization and accretion	**986**	839	905
Taxes other than on income	**557**	508	501
Other	**13**	(3)	30
Total operating expenses	**8,113**	7,484	7,607
Operating income	**1,772**	1,683	1,546
Other income (expense)			
Interest income	**14**	24	34
Allowance for equity funds used during construction	**124**	122	51
Other, net	**6**	(17)	(7)
Total other income, net	**144**	129	78
Interest charges			
Interest charges	**718**	679	605
Allowance for borrowed funds used during construction	**(39)**	(40)	(17)
Total interest charges, net	**679**	639	588
Income from continuing operations before income tax	**1,237**	1,173	1,036
Income tax expense	**397**	395	334
Income from continuing operations	**840**	778	702
Discontinued operations, net of tax	**(79)**	58	(206)
Net income	**761**	836	496
Net (income) loss attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Net income attributable to controlling interests	**$757**	$830	$504
Average common shares outstanding – basic	**279**	262	257
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	**$2.99**	$2.95	$2.70
Discontinued operations attributable to controlling interests, net of tax	**(0.28)**	0.22	(0.74)
Net income attributable to controlling interests	**$2.71**	$3.17	$1.96
Dividends declared per common share	**$2.480**	$2.465	$2.445
Amounts attributable to controlling interests			
Income from continuing operations attributable to controlling interests, net of tax	**$836**	$773	$693
Discontinued operations attributable to controlling interests, net of tax	**(79)**	57	(189)
Net income attributable to controlling interests	**$757**	$830	$504

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2009	2008
ASSETS		
Utility plant		
Utility plant in service	$28,918	$26,326
Accumulated depreciation	(11,576)	(11,298)
Utility plant in service, net	17,342	15,028
Held for future use	47	38
Construction work in progress	1,790	2,745
Nuclear fuel, net of amortization	554	482
Total utility plant, net	19,733	18,293
Current assets		
Cash and cash equivalents	725	180
Receivables, net	800	867
Inventory	1,325	1,239
Regulatory assets	142	533
Derivative collateral posted	146	353
Income taxes receivable	145	194
Prepayments and other current assets	248	154
Total current assets	3,531	3,520
Deferred debits and other assets		
Regulatory assets	2,179	2,567
Nuclear decommissioning trust funds	1,367	1,089
Miscellaneous other property and investments	438	446
Goodwill	3,655	3,655
Other assets and deferred debits	333	303
Total deferred debits and other assets	7,972	8,060
Total assets	$31,236	$29,873
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 281 million and 264 million shares issued and outstanding, respectively	$6,873	$6,206
Unearned ESOP shares (1 million shares)	(12)	(25)
Accumulated other comprehensive loss	(87)	(116)
Retained earnings	2,675	2,622
Total common stock equity	9,449	8,687
Noncontrolling interests	6	6
Total equity	9,455	8,693
Preferred stock of subsidiaries	93	93
Long-term debt, affiliate	272	272
Long-term debt, net	11,779	10,387
Total capitalization	21,599	19,445
Current liabilities		
Current portion of long-term debt	406	–
Short-term debt	140	1,050
Accounts payable	835	912
Interest accrued	206	167
Dividends declared	175	164
Customer deposits	300	282
Derivative liabilities	190	493
Accrued compensation and other benefits	167	193
Other current liabilities	239	225
Total current liabilities	2,658	3,486
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,196	818
Accumulated deferred investment tax credits	117	127
Regulatory liabilities	2,510	2,181
Asset retirement obligations	1,170	1,471
Accrued pension and other benefits	1,339	1,594
Capital lease obligations	221	231
Derivative liabilities	240	269
Other liabilities and deferred credits	186	251
Total deferred credits and other liabilities	6,979	6,942
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$31,236	$29,873

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	**2009**	2008	2007
Operating activities			
Net income	**$761**	$836	$496
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	**1,135**	957	1,026
Deferred income taxes and investment tax credits, net	**220**	411	177
Deferred fuel cost (credit)	**290**	(333)	117
Deferred income	**–**	–	(128)
Allowance for equity funds used during construction	**(124)**	(122)	(51)
Loss (gain) on sales of assets	**2**	(75)	(29)
Other adjustments to net income	**269**	135	212
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**26**	233	(186)
Inventory	**(99)**	(237)	(11)
Derivative collateral posted	**200**	(340)	55
Prepayments and other current assets	**3**	7	35
Income taxes, net	**(14)**	(169)	(275)
Accounts payable	**(26)**	77	(40)
Other current liabilities	**(42)**	(103)	81
Other assets and deferred debits	**11**	(44)	(198)
Accrued pension and other benefits	**(285)**	(39)	(91)
Other liabilities and deferred credits	**(56)**	24	62
Net cash provided by operating activities	**2,271**	1,218	1,252
Investing activities			
Gross property additions	**(2,295)**	(2,333)	(1,973)
Nuclear fuel additions	**(200)**	(222)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**1**	72	675
Purchases of available-for-sale securities and other investments	**(2,350)**	(1,590)	(1,413)
Proceeds from available-for-sale securities and other investments	**2,314**	1,534	1,452
Other investing activities	**(2)**	(2)	30
Net cash used by investing activities	**(2,532)**	(2,541)	(1,457)
Financing activities			
Issuance of common stock	**623**	132	151
Dividends paid on common stock	**(693)**	(642)	(627)
Payments of short-term debt with original maturities greater than 90 days	**(29)**	(176)	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	**–**	29	176
Net (decrease) increase in short-term debt	**(981)**	1,096	25
Proceeds from issuance of long-term debt, net	**2,278**	1,797	739
Retirement of long-term debt	**(400)**	(877)	(324)
Cash distributions to noncontrolling interests	**(6)**	(85)	(10)
Other financing activities	**14**	(26)	65
Net cash provided by financing activities	**806**	1,248	195
Net increase (decrease) in cash and cash equivalents	**545**	(75)	(10)
Cash and cash equivalents at beginning of year	**180**	255	265
Cash and cash equivalents at end of year	**$725**	$180	$255
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	**$701**	$612	$585
Income taxes, net of refunds	**87**	152	176
Significant noncash transactions			
Capital lease obligation incurred	**–**	–	182
Accrued property additions	**252**	334	329
Asset retirement obligation additions and estimate revisions	**(384)**	14	–

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN TOTAL EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling Interests	Total Equity
Balance, December 31, 2006	**256**	**$5,791**	**$(50)**	**$(49)**	**$2,567**	**$10**	**$8,269**
Net income		–	–	–	504	(8)	496
Other comprehensive income		–	–	15	–	–	15
Adjustment to initially apply FASB Interpretation No. 48		–	–	–	(2)	–	(2)
Issuance of shares	4	46	–	–	–	–	46
Stock options exercised		105	–	–	–	–	105
Allocation of ESOP shares		15	13	–	–	–	28
Stock-based compensation expense		71	–	–	–	–	71
Dividends ($2.445 per share)		–	–	–	(631)	–	(631)
Sale of subsidiary shares to noncontrolling interests		–	–	–	–	37	37
Distributions to noncontrolling interests		–	–	–	–	(10)	(10)
Contributions from noncontrolling interests		–	–	–	–	52	52
Other transactions		–	–	–	–	3	3
Balance, December 31, 2007	**260**	**6,028**	**(37)**	**(34)**	**2,438**	**84**	**8,479**
Net income		–	–	–	830	6	836
Other comprehensive loss		–	–	(82)	–	–	(82)
Issuance of shares	4	131	–	–	–	–	131
Stock options exercised		1	–	–	–	–	1
Allocation of ESOP shares		13	12	–	–	–	25
Stock-based compensation expense		33	–	–	–	–	33
Dividends ($2.465 per share)		–	–	–	(646)	–	(646)
Distributions to noncontrolling interests		–	–	–	–	(85)	(85)
Contributions from noncontrolling interests		–	–	–	–	2	2
Other transactions		–	–	–	–	(1)	(1)
Balance, December 31, 2008	**264**	**6,206**	**(25)**	**(116)**	**2,622**	**6**	**8,693**
Net income[(a)]		**–**	**–**	**–**	**757**	**–**	**757**
Other comprehensive income		**–**	**–**	**29**	**–**	**–**	**29**
Issuance of shares	**17**	**623**	**–**	**–**	**–**	**–**	**623**
Allocation of ESOP shares		**8**	**13**	**–**	**–**	**–**	**21**
Stock-based compensation expense		**36**	**–**	**–**	**–**	**–**	**36**
Dividends ($2.480 per share)		**–**	**–**	**–**	**(704)**	**–**	**(704)**
Distributions to noncontrolling interests		**–**	**–**	**–**	**–**	**(1)**	**(1)**
Other transactions		**–**	**–**	**–**	**–**	**1**	**1**
Balance, December 31, 2009	**281**	**$6,873**	**$(12)**	**$(87)**	**$2,675**	**$6**	**$9,455**

[(a)] Consolidated net income of $761 million includes $4 million attributable to preferred shareholders of subsidiaries, which is not a component of total equity and is excluded from the table above.

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2009	2008	2007
Net income	**$761**	$836	$496
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $4, $2 and $3, respectively)	**6**	3	4
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $3, $1 and $1, respectively)	**4**	1	2
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(10), $24 and $8, respectively)	**16**	(37)	(13)
Net unrecognized items on pension and other postretirement benefits (net of tax (expense) benefit of $(1), $29 and $(16), respectively)	**2**	(49)	23
Other (net of tax benefit of $-, $1 and $3, respectively)	**1**	–	(1)
Other comprehensive income (loss)	**29**	(82)	15
Comprehensive income	**790**	754	511
Comprehensive (income) loss attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Comprehensive income attributable to controlling interests	**$786**	$748	$519

See Notes to Consolidated Financial Statements.

In this report, Progress Energy (which includes Progress Energy, Inc. holding company [the Parent] and its regulated and nonregulated subsidiaries on a consolidated basis) is at times referred to as "we," "us" or "our." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities."

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

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

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

PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), the NRC and the FERC.

See Note 19 for further information about our segments.

B. Basis of Presentation

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), including GAAP for regulated operations. The financial statements include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements.

Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in noncontrolling interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for noncontrolling interests are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis. Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by GAAP for regulated operations, which provides that profits on intercompany sales to regulated affiliates are not eliminated, if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under GAAP.

These notes accompany and form an integral part of Progress Energy's consolidated financial statements.

Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

C. Consolidation of Variable Interest Entities

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

In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance, which makes significant changes to the model for determining who should consolidate a VIE and addresses how often this assessment should be performed. See Note 2 for further discussion regarding the new guidance, which requires all existing arrangements with VIEs to be evaluated, and any impacts of adoption accounted for as a cumulative-effect adjustment. The guidance is effective for us on January 1, 2010. We do not expect the adoption to have a significant impact on our financial position, results of operations and cash flows.

In addition to the following variable interests listed for PEC, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2008 or 2009. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2009, we had no assets and $3 million of liabilities related to tax indemnifications provided to the buyer included in other liabilities and deferred credits on the Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the gain on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 22C for a general discussion of guarantees. See Note 22D for discussion of recent developments related to legal indemnifications.

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Internal Revenue Code (the Code). PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2007 through 2009. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2009, PEC had assets of $39 million, substantially all of which was reflected in miscellaneous other property and investment, and $15 million in long-term debt, $3 million in other liabilities and deferred credits and $5 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE PEC INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (MW). PEC has requested the necessary information to determine if the investment fund's 17 partnerships and the power plant owner are VIEs or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC, and, accordingly, PEC has applied the information scope exception provided by GAAP to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the power plant and the investment fund consolidating the 17 partnerships would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparties, the impact cannot be determined at this time.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility base revenues earned when service has been delivered but not billed by the end of the accounting period. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

Fuel expense includes fuel costs and other recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs, fuel-related costs and portions of purchased power costs through surcharges on customer rates. These deferred fuel costs are recognized in revenues and fuel expenses as they are billable to customers.

EXCISE TAXES

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

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007, were $333 million, $295 million and $299 million, respectively.

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of GAAP.

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with PUHCA 2005. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations (AROs) are charged to a regulatory liability.

Allowance for funds used during construction (AFUDC) represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform system of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges.

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Consolidated Balance Sheets. Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 7).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the FERC.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002 and froze North Carolina electric utility base rates for a five-year period, which ended in December 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for the amortization and recovery of 70 percent of the original estimated compliance costs for the Clean Smokestacks Act while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. In September 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks compliance costs (See Note 7B).

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

INVENTORY

We account for inventory, including emission allowances, using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are established for excess and obsolete inventory.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

GOODWILL AND INTANGIBLE ASSETS

Goodwill is subject to at least an annual assessment for impairment by applying a two-step, fair value-based test. This assessment could result in periodic impairment charges. Intangible assets are amortized based on the economic benefit of their respective lives.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when the book and tax carrying amounts of assets and liabilities differ. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net in the Consolidated Statements of Income.

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. We do not accrue an estimate of legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for loss contingencies have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our equity investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline in value exists, the investments are written down to fair value with a new cost basis established.

2. NEW ACCOUNTING STANDARDS

Effective July 1, 2009, changes to the source of authoritative U.S. GAAP, the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC), are communicated through an Accounting Standards Update (ASU). ASUs will be published for all authoritative U.S. GAAP promulgated by the FASB, regardless of the form in which such guidance may have been issued prior to release of the FASB Codification (e.g., FASB Statements, FASB Staff Positions, etc.).

ASC 810 Consolidations

On January 1, 2009, we implemented ASC 810-10-65, which was previously referred to as Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." ASC 810-10-65 introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. The adoption of ASC 810-10-65 resulted in a retrospective change in presentation of the financial statements for all periods presented and additional disclosures but did not have a material impact on our financial position or results of operations.

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

ASC 815-10-65 (SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133")

On January 1, 2009, we implemented ASC 815-10-65, which was previously referred to as SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133." ASC 815-10-65 requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and its related interpretations and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. See Note 17 for information regarding our first quarter 2009 implementation of ASC 815-10-65. The adoption of ASC 815-10-65 did not have a material impact on our financial position or results of operations.

ASC 260-10-45 (FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities")

On January 1, 2009, we implemented ASC 260-10-45, which was previously referred to as FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." ASC 260-10-45 requires that certain unvested share-based payment awards (e.g., restricted stock) that contain nonforfeitable rights to dividends or dividend equivalents be included in the computation of earnings per share using the two-class method. ASC 260-10-45 requires a retrospective adjustment for all prior-period earnings per share data. The adoption of ASC 260-10-45 did not have a material impact on our financial position, results of operations or earnings per share amounts.

Fair Value Measurement and Disclosures and Other-Than-Temporary Impairments

In April 2009, the FASB issued three FSPs for guidance on accounting for fair value measurement and other-than-temporary impairments.

ASC 820 includes the FSP previously referred to as FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," and provides guidance on determining fair value when market activity has decreased for an asset or liability. ASC 825-10-50, previously referred to as FSP FAS 107-1 and APB 28-1, "Interim Disclosures About Fair Value of

Financial Instruments," increases the frequency of fair value disclosures required from annually to quarterly.

ASC 320 includes the FSPs previously referred to as FSP FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," and revises the recognition and reporting requirements for other-than-temporary impairments of debt securities and increases the frequency of disclosures for debt and equity securities. Under ASC 320, if an entity intends to sell an impaired debt security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, an other-than-temporary impairment must be recognized currently in earnings equal to the difference between the investment's amortized cost and its fair value at the balance sheet date.

The new guidance in ASC 820, ASC 825 and ASC 320 was effective for us during the three months ended June 30, 2009. The adoption resulted in additional disclosures but did not have a material impact on our financial position or results of operations. See Note 13 for the disclosures resulting from the implementation of this guidance in 2009.

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends ASC 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 was effective for us on January 1, 2010, with certain disclosures effective for periods beginning January 1, 2011. The adoption of ASU 2010-06 will change certain disclosures in the notes to the financial statements, but will have no impact on our financial position or results of operations.

ASC 715-20-65 (FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets")

In December 2008, the FASB issued ASC 715-20-65, previously referred to as FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets," which requires additional disclosures on the investment allocation decision-making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. ASC 715-20-65 was effective for us on December 31, 2009. The adoption of ASC 715-20-65 resulted in additional disclosures, but did not have a material impact on our financial position or results of operations. See Note 16 for the information regarding our implementation of ASC 715-20-65.

ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)"

In September 2009, the FASB issued ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)," which provides additional guidance related to measuring the fair value of certain alternative investments, such as interests in hedge funds, private equity funds, real estate funds, venture capital funds, offshore fund vehicles, and funds of funds. ASU 2009-12 allows reporting entities to use net asset value per share to estimate the fair value of certain investments as a practical expedient and requires disclosures by major category of investment about the attributes of the investments. ASU 2009-12 was effective for us on December 31, 2009. The adoption of ASU 2009-12 did not have a material impact on our financial position or results of operations.

3. DIVESTITURES

We completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. Terminals Operations and Synthetic Fuels Businesses

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements reflect the operations of Terminals as discontinued operations.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability of $16 million, and $4 million related to other legal and tax contingency adjustments. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

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

(in millions)	**2009**	2008	2007
Revenues	**$–**	$17	$1,126
(Loss) earnings before income taxes and noncontrolling interest	**$(125)**	$8	$2
Income tax benefit, including tax credits	**47**	12	64
(Loss) earnings attributable to noncontrolling interests of Synthetic Fuels	**–**	(1)	17
Net (loss) earnings from discontinued operations attributable to controlling interests	**(78)**	19	83
Gain on disposal of discontinued operations, including income tax expense of $7	**–**	42	–
(Loss) earnings from discontinued operations attributable to controlling interests	**$(78)**	$61	$83

B. Coal Mining Businesses

On March 7, 2008, we sold the remaining operations of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels) subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets. During 2009, we recognized a $1 million loss as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the Coal Mining as discontinued operations. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Revenues	**$–**	$2	$28
Loss before income taxes	**$(2)**	$(13)	$(17)
Income tax benefit	**1**	4	6
Net loss from discontinued operations	**(1)**	(9)	(11)
Gain on disposal of discontinued operations, including income tax expense of $2	**–**	7	–
Loss from discontinued operations attributable to controlling interests	**$(1)**	$(2)	$(11)

C. CCO – Georgia Operations

On March 9, 2007, our subsidiary, Progress Energy Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of a previously recorded impairment, respectively.

Additionally, on June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represented substantially all of our nonregulated energy marketing and trading operations. As a result of the assignments, PVI made a net cash payment of $347 million, which represented the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax (charge included in the net loss from discontinued operations in the table below). We used the net proceeds from the divestiture of CCO and the Georgia Contracts for general corporate purposes. During 2008 and 2009, we recognized a $5 million loss and a $1 million gain, respectively, as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense was allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the year ended December 31, 2007, was $11 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2009**	2008	2007
Revenues	**$–**	$–	$407
Loss before income taxes	**$(1)**	$(5)	$(449)
Income tax benefit	**2**	2	166
Net earnings (loss) from discontinued operations	**1**	(3)	(283)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $7, respectively	**–**	(2)	18
Earnings (loss) from discontinued operations attributable to controlling interests	**$1**	$(5)	$(265)

D. Other Diversified Businesses

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses, primarily Progress Rail Services Corporation. We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2009, we recorded an after-tax loss on disposal of $1 million and after-tax gains of $3 million and $4 million for the years ended December 31, 2008 and 2007, respectively. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

E. Ceredo Synthetic Fuels Interests

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo, a subsidiary that produced and sold qualifying coal-based solid synthetic fuels, to a third-party buyer. In addition, we entered into an agreement to operate the Ceredo facility on behalf of the buyer. At closing, we received cash proceeds of $10 million and a nonrecourse note receivable of $54 million. Payments on the note were received as we produced and sold qualifying coal-based solid synthetic fuels on behalf of the buyer. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million during the year ended December 31, 2007, and a final payment of $5 million during the year ended December 31, 2008. The note had an interest rate equal to the three-month London Inter Bank Offered Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million. Under the terms of the agreement, the purchase price was reduced by $7 million during the year ended December 31, 2008, based on the final value of the 2007 Section 29/45K tax credits.

During the year ended December 31, 2008, we recognized previously deferred gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with GAAP for variable interest entities, but record a 100 percent noncontrolling interest.

4. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

The balances of electric utility plant in service at December 31 are listed below, with a range of depreciable lives (in years) for each:

(in millions)	Depreciable Lives	**2009**	2008
Production plant	7-43	**$16,042**	$14,117
Transmission plant	17-75	**3,273**	2,970
Distribution plant	13-55	**8,376**	8,028
General plant and other	5-35	**1,227**	1,211
Utility plant in service		**$28,918**	$26,326

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 11).

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 9.2%, 9.2% and 8.8% in 2009, 2008 and 2007, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2009, 2008 and 2007.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.4% in 2009, 2008 and 2007, respectively.

The depreciation provisions related to utility plant were $626 million, $578 million and $560 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

Nuclear fuel, net of amortization at December 31, 2009 and 2008, was $554 million and $482 million, respectively. The amount not yet in service at December 31, 2009 and 2008, was $308 million and $243 million, respectively. Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $159 million, $145 million and $139 million for the years ended December 31, 2009, 2008 and 2007, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEF's construction work in progress related to certain nuclear projects has received regulatory treatment. At December 31, 2009, PEF reflected $296 million of construction work in progress, $274 million of which was reflected as a nuclear cost-recovery clause regulatory asset (See Note 7C) and $22 million was reflected as a deferred fuel regulatory asset. At December 31, 2008, PEF reflected $174 million of construction work in progress as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

B. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the jointly owned generating facilities is included within the corresponding line in the Consolidated Statements of Income. The co-owner of Intercession City Unit P11 has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

2009

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	**Mayo**	**83.83%**	**$785**	**$282**	**$8**
PEC	**Harris**	**83.83%**	**3,207**	**1,651**	**28**
PEC	**Brunswick**	**81.67%**	**1,681**	**981**	**74**
PEC	**Roxboro Unit 4**	**87.06%**	**686**	**449**	**15**
PEF	**Crystal River Unit 3**	**91.78%**	**900**	**472**	**510**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**10**	**–**

2008

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

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris), which are not applicable to the joint owner's ownership interest in Harris.

C. Asset Retirement Obligations

At December 31, 2009 and 2008, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $132 million and $163 million, respectively. The fair value of funds set aside in the Utilities' NDT funds for the nuclear decommissioning liability totaled $1.367 billion and $1.089 billion at December 31, 2009 and 2008, respectively (See Notes 12 and 13). Net NDT unrealized gains are included in regulatory liabilities (See Note 7A).

Our nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2009, 2008 and 2007. As discussed below, PEF has suspended its accrual for nuclear decommissioning. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense, were $141 million, $133 million and $126 million in 2009, 2008 and 2007, respectively.

During 2009, PEF submitted a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study is expected to have an insignificant impact on cost of removal expense in 2010.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 7A). At December 31, such costs consisted of:

(in millions)	**2009**	2008
Removal costs	**$1,532**	$1,478
Nonirradiated decommissioning costs	**211**	146
Dismantlement costs	**123**	124
Non-ARO cost of removal	**$1,866**	$1,748

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris Nuclear Plant (Harris) Unit No. 1, in December 2009, which will be filed with the NCUC in the first quarter of 2010. PEC's estimate is based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. See Note 7D for information about the NRC operating licenses held by PEC. Based on updated cost estimates, in 2009 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $27 million and $390 million, respectively, resulting in no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2009.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing (See Note 7C). However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF will not be required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF will be required to update the 2008 study with the most currently available escalation rates in 2010. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. See Note 7D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate and assumed operating license renewal, PEF increased its asset retirement cost and its ARO liability by approximately $19 million in 2008. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its planned 2010 nuclear decommissioning filing. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. PEF's reserve for fossil plant dismantlement was approximately $143 million and $145 million at December 31, 2009 and 2008, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended under the terms of previous base rate settlement agreements.

The Utilities have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $54 million and $45 million at December 31, 2009 and 2008, respectively.

Additionally, the Utilities have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $7 million at December 31, 2009 and 2008. For PEC, closure work related to the landfill commenced in 2009 and should be completed in 2010.

We have identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by us. These easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The ARO is not estimable for such easements, as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The following table presents the changes to the AROs during the years ended December 31, 2009 and 2008. Revisions to prior estimates of the regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

(in millions)	
Asset retirement obligations at January 1, 2008	$1,378
Additions	7
Accretion expense	79
Revisions to prior estimates	7
Asset retirement obligations at December 31, 2008	1,471
Accretion expense	**83**
Revisions to prior estimates	**(384)**
Asset retirement obligations at December 31, 2009	**$1,170**

D. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $28 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $12.595 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified acts, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply.

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

5. RECEIVABLES

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

(in millions)	**2009**	2008
Trade accounts receivable	**$581**	$648
Unbilled accounts receivable	**193**	182
Notes receivable	–	2
Derivatives accounts receivable	**2**	–
Other receivables	**42**	53
Allowance for doubtful receivables	**(18)**	(18)
Total receivables, net	**$800**	$867

6. INVENTORY

At December 31 inventory was comprised of:

(in millions)	**2009**	2008
Fuel for production	**$667**	$614
Materials and supplies	**639**	588
Emission allowances	**18**	37
Other	**1**	–
Total inventory	**$1,325**	$1,239

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets of $24 million and $23 million at December 31, 2009 and 2008, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets of $39 million and $61 million, respectively, at December 31, 2009 and 2008.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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

(in millions)	**2009**	2008
Deferred fuel cost – current (Notes 7B and 7C)	**$105**	$335
Nuclear deferral (Note 7C)	**37**	190
Environmental	**–**	8
Total current regulatory assets	**142**	533
Deferred fuel cost – long-term (Note 7B)[a]	**62**	130
Nuclear deferral (Note 7C)[a]	**239**	–
Deferred impact of ARO (Note 4C)[b]	**99**	348
Income taxes recoverable through future rates[b]	**264**	193
Loss on reacquired debt[c]	**35**	37
Storm deferral (Note 7C)[d]	**10**	16
Postretirement benefits (Note 16)[e]	**945**	1,042
Derivative mark-to-market adjustment (Note 17A)[f]	**436**	697
Environmental (Notes 7C and 21A)[g]	**24**	31
Accrued vacation[a]	**10**	32
DSM/Energy-efficiency deferral (Note 7B)[h]	**19**	9
Other	**36**	32
Total long-term regulatory assets	**2,179**	2,567
Environmental (Note 7C)	**(24)**	–
Deferred energy conservation cost and other current regulatory liabilities	**(3)**	(6)
Total current regulatory liabilities	**(27)**	(6)
Non-ARO cost of removal (Note 4C)[b]	**(1,866)**	(1,748)
Deferred impact of ARO (Note 4C)[b]	**(150)**	(198)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	**(295)**	(28)
Derivative mark-to-market adjustment (Note 17A)[f]	**(20)**	(26)
Storm reserve (Note 7C)[g]	**(136)**	(129)
Other	**(43)**	(52)
Total long-term regulatory liabilities	**(2,510)**	(2,181)
Net regulatory (liabilities) assets	**$(216)**	$913

The recovery and amortization periods for these regulatory assets and (liabilities) at 2009 are as follows:

[a] Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

[b] Asset retirement and removal liabilities are recorded and income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and adjusted following completion of the related activities.

[c] Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

[d] Recorded and recovered or amortized as approved by the FERC over a period not exceeding five years.

[e] Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 7C).

[f] Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After settlement of the derivatives and the fuel is consumed, the realized gains or losses are passed through the fuel cost-recovery clause.

[g] Recovered as environmental remediation or storm restoration expenses are incurred.

[h] Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

[i] Related to unrealized gains and losses on nuclear decommissioning trust funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

B. PEC Retail Rate Matters

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75 percent. In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended December 31, 2007, unless there were extraordinary events beyond the control of the utilities or unless the utilities persistently earned a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. There were no adjustments to PEC's base rates during the five-year period ended December 31, 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. During the rate freeze period, the legislation provided for a minimum amortization and recovery of 70 percent of the original estimated compliance costs of $813 million (or $569 million) while providing flexibility in the amount of annual amortization recorded from none up to $174 million per year.

For the years ended December 31, 2008 and 2007, PEC recognized Clean Smokestacks Act amortization of $15 million and $34 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC did not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful lives of the assets.

See Note 21B for additional information about the Clean Smokestacks Act.

FUEL COST RECOVERY

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On May 28, 2009, PEC jointly filed a settlement agreement with the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million. On June 19, 2009, the SCPSC approved the settlement agreement. The decrease was effective July 1, 2009, and decreased residential electric bills by $2.08 per 1,000 kilowatt-hours (kWh), or 2.0 percent, for fuel cost recovery. At December 31, 2009, PEC's South Carolina under-recovered deferred fuel balance was $2 million.

On June 4, 2009, and as updated on August 17, 2009, PEC filed with the NCUC for a $14 million decrease in the fuel rate charged to its North Carolina ratepayers, driven by declining fuel prices. On November 16, 2009, the NCUC approved PEC's request. Effective December 1, 2009, residential electric bills decreased by $0.45 per 1,000 kWh, or 0.4 percent, for fuel cost recovery. At December 31, 2009, PEC's North Carolina under-recovered deferred fuel balance was $148 million, $62 million of which is expected to be collected after 2010 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

Comprehensive energy legislation enacted by North Carolina in 2007 allows PEC to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of the DSM and energy-efficiency filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results. At December 31, 2009, PEC's deferred North Carolina DSM and energy-efficiency costs totaled $15 million.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency rider to recover all program costs, including the recovery of appropriate incentives for investing in such programs. On November 14, 2008, the NCUC issued an order allowing PEC to implement the rates requested in PEC's November 14, 2008 revision to its initial application. The new rates, subject to true-up to the final order, were implemented on December 1, 2008, increasing residential electrical bills by $0.74 per 1,000 kWh, or 0.8 percent. As a result of settlement agreements entered into in 2007 and resulting regulatory proceedings, the NCUC ordered PEC to recalculate rates and submit to the NCUC for approval. The 2009 impact of these revised rates was immaterial.

On June 4, 2009, and as updated on August 17, 2009, PEC requested the NCUC approve a $1 million increase in the DSM and energy-efficiency rate charged to its North Carolina ratepayers. Due to changes in how the costs are allocated among customer classes, the request results in a decrease to the residential rate, while increasing rates for other customer classes. The rate change was approved on an interim basis effective December 1, 2009, and decreased residential electric bills by $0.19 per 1,000 kWh, or 0.2 percent.

On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. On May 6, 2009, the SCPSC approved the Stipulation Agreement and issued a directive requiring PEC to file for approval of all proposed DSM and energy-efficiency programs. On May 11, 2009, in accordance with the SCPSC directive, PEC filed its programs for approval and an application for a cost-recovery rider for PEC's DSM and energy-efficiency programs. On June 10, 2009, SCPSC approved the proposed DSM and energy-efficiency programs and the cost-recovery rider application, on a provisional basis pending a review of the cost-recovery rider by the South Carolina Office of Regulatory Staff. The rate increase was effective July 1, 2009, and increased residential electric bills by $0.79 per 1,000 kWh, or 0.8 percent, for DSM and energy-efficiency cost recovery. We cannot predict the outcome of this matter. At December 31, 2009, PEC's deferred South Carolina DSM and energy-efficiency costs totaled $4 million.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

Beginning in 2009, PEC is required to file an annual North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC has selected APX, Inc. as the vendor for implementation of a statewide REC tracking system. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, will participate in the registry. Rates for the NC REPS clause are set based on projected costs with true-up provisions. On June 4, 2009 and as updated August 17, 2009, PEC filed with the NCUC for a $7 million increase in the NC REPS rate charged to its North Carolina ratepayers. On November 12, 2009, the NCUC approved PEC's request effective December 1, 2009. PEC's residential electric bills increased by $0.29 per month, or 0.3 percent, for renewable energy portfolio standard (REPS) cost recovery.

ENVIRONMENTAL COMPLIANCE COST RECOVERY

On February 11, 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental operation and maintenance expenses that PEC incurs in connection with its environmental compliance control facilities. At December 31, 2009, PEC's South Carolina environmental compliance cost-recovery balance was $5 million.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery were $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. PEC reached the minimum amount of $415 million of cost recovery by December 31, 2008, and no additional depreciation expense from accelerated cost recovery was recorded in 2009. The South Carolina aggregate minimum and maximum amounts of cost recovery were $115 million and $165 million, respectively. Prior to the SCPSC's 2008 approval to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets, PEC had recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction. As a result of the SCPSC's 2008 approval, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful lives of the assets. No additional depreciation expense from accelerated cost recovery for the South Carolina jurisdiction was recorded in 2009, 2008 or 2007.

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on July 1, 2008. On May 15, 2009, PEC filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $4 million.

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

North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. On August 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility would be in service by January 2013. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units, with a combined generating capacity of approximately 400 MW, that are currently in operation at the site. This will result in approximately 550 MW of incremental capacity. On September 21, 2009, the Public Staff recommended that the NCUC issue the certificate subject to additional conditions as follows: the facility be constructed and operated in accordance with all applicable laws and regulations, PEC file with the NCUC a progress report and any revisions in the cost estimates on an annual basis, PEC permanently cease operation of the three coal-fired units immediately upon completion and placement into service of the facility and that the NCUC clarify that the issuance of the certificate does not constitute approval of the final costs associated with construction of the facility. On October 1, 2009, the NCUC issued a notice of decision stating it found good cause to issue an order granting PEC the certificate subject to the four conditions proposed by the Public Staff as well as adding a condition that PEC submit for NCUC approval a plan to retire additional coal-fired capacity reasonably proportionate to the 550 MW of incremental capacity. On October 22, 2009, the NCUC issued its order granting PEC the certificate to construct the 950-MW facility.

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

On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. PEC projects that the generating facility would be in service by late 2013 or early 2014. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units currently in operation at the site that do not have scrubbers. These units have a combined generating capacity of approximately 600 MW.

C. PEF Retail Rate Matters

BASE RATES

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. Based on actual energy sales, the interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009. The changes increased residential bills by approximately $4.52 per 1,000 kWh, or 3.7 percent. On July 2, 2009, Florida's Office of Public Counsel (OPC), the Florida Industrial Power Users Group, the attorney general, the Florida Retail Federation and PCS Phosphate filed a petition protesting portions of the FPSC approval. On August 31, 2009, the FPSC issued an order to consolidate the interim and limited base rate relief increase and the base rate proposal. PEF's remaining base rate request as filed by PEF would have increased residential bills by approximately $9.66 per 1,000 kWh, or 7.6 percent, effective January 1, 2010. A hearing was held on this matter September 21, 2009 – October 1, 2009. On October 27, 2009, the FPSC held a hearing to determine if the voting of pending rate cases should be delayed until new FPSC appointees took office in January 2010. During the hearing, the FPSC voted to delay the rulings on the appropriate level of revenue requirements until January 11, 2010.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual operating and maintenance (O&M) costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options in Florida.

FUEL COST RECOVERY

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced residential customers' fuel charges by $6.90 per 1,000 kWh, or 5.0 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On August 10, 2006, Florida's OPC filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers alleged excessive past fuel-recovery charges and SO_2 allowance costs during the period 1996 to 2005. During the period specified in the petition, PEF's costs recovered through fuel-recovery clauses were annually reviewed for prudence and approval by the FPSC. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability. The refund was returned to ratepayers in 2008 through a reduction of prior year under-recovered fuel costs. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for Crystal River Units No. 4 and 5 coal-fired steam turbines (CR4 and CR5). On February 2, 2009, the OPC filed direct testimony alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 plants. During the hearing on the matter, the OPC reduced the alleged excessive fuel costs to $33 million before interest. On June 30, 2009, the FPSC approved a refund of $8 million to PEF's ratepayers to be paid over a 12-month period beginning January 1, 2010, and ordered PEF to file a report by September 2009 regarding the prospective application of PEF's coal procurement plan and the prudence of PEF's coal procurement actions. In compliance with the FPSC order, PEF filed the coal procurement status report on September 14, 2009. For the year ended December 31, 2009, PEF recorded a pre-tax other operating expense of $8 million, an immaterial amount of interest and an associated regulatory liability included within PEF's deferred fuel cost at December 31, 2009. PEF chose not to appeal the FPSC's order.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. This decrease is due to a decrease of $9.89 per 1,000 kWh for the projected recovery of fuel costs, partially offset by an increase of $6.55 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause (CCRC). The decrease in projected fuel costs is due primarily to a decrease in the price of natural gas and a change in the expected average fuel costs. An extended biennial nuclear outage at CR3 for an uprate project in 2009 contributed to higher projected fuel costs for 2009; however, anticipated changes in the generation mix for 2010 are expected to result in lower average fuel costs and contributed to the projected decrease in 2010 fuel costs. The increase in the CCRC is primarily the result of projected costs to be incurred in 2010 under the nuclear cost-recovery rule discussed below for the proposed nuclear plant in Levy County, Fla. (Levy) and an under-recovery of purchased power costs in 2009. On October 23, 2009, as a result of the October 16, 2009 FPSC vote in the nuclear cost-recovery matter discussed more fully below, PEF filed a $3 million cost adjustment with the FPSC, which reduced the CCRC rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost-adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

On August 28, 2009, PEF filed a request to increase the Environmental Cost Recovery Clause (ECRC) residential rate and the filing was updated on October 27, 2009. PEF is asking the FPSC to increase residential rates by $2.25 per 1,000 kWh, or 1.8 percent. This would increase projected revenues by $33 million. This increase is primarily due to the return on assets expected to be placed in service at the end of 2009. On September 14, 2009, PEF filed a request to increase the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.47 per 1,000 kWh, or 0.4 percent. This would increase projected revenues by $4 million. This increase is due mainly to an increase in conservation program costs. The FPSC approved PEF's ECRC and ECCR clause filings on November 2, 2009, to be effective January 1, 2010.

NUCLEAR COST RECOVERY

Levy Nuclear

On March 11, 2008, PEF filed a petition for an affirmative Determination of Need for its proposed Levy Units 1 and 2 nuclear power plants, together with the associated facilities, including transmission lines and substation facilities. Levy Units 1 and 2 are needed to maintain electric system reliability and integrity, fuel and generating diversity and to continue to provide adequate electricity to PEF's customers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. The FPSC issued the final order granting the petition for the Determination of Need for the proposed nuclear units on August 12, 2008.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of Levy. PEF filed the petition to assist the FPSC in the timely and adequate review of the proposed project's costs recoverable under the nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for Levy, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced residential customers' nuclear cost-recovery charge by $7.80 per 1,000 kWh, or 5.7 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing, which would result in a nuclear cost-recovery charge of either $7.98 per 1,000 kWh for residential customers under PEF's alternate proposal, or $15.07 per 1,000 kWh if the FPSC did not approve PEF's alternate proposal. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million of revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. This revenue level results in a nuclear cost-recovery charge of $6.99 per 1,000 kWh, which represents a $2.68 increase per 1,000 kWh for residential customer bills. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

On October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule. Specifically, the FPSC clarified that (1) nuclear costs are deemed to be recovered up to the amount of FPSC-approved projections and (2) the deferral of unrecovered nuclear costs would accrue a carrying charge at PEF's approved AFUDC rate consistent with the requirements of FPSC's nuclear cost-recovery rule, which is fixed at the pre-tax AFUDC rate in effect as of June 12, 2007. Accordingly, PEF retrospectively assigned capacity revenues to match the FPSC-approved projected level of nuclear cost recovery as of September 30, 2009. Nuclear costs incurred in excess of original projections earn a carrying charge equal to the AFUDC rate. Prior to the FPSC clarification, PEF assigned capacity revenues to nuclear cost recovery based on actual costs incurred; any over- or under-recoveries of actual costs were deferred and earned a carrying charge equal to a commercial paper rate.

On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs as a part of PEF's proposed rate management plan. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of the 1) $198 million of capacity revenues and 2) the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

The FPSC has authorized alternative cost-recovery mechanisms for preconstruction and construction carrying costs of nuclear power plants. Accordingly, at December 31, 2009 and 2008, PEF reflected $276 million and $190 million, respectively, of nuclear-related costs as a regulatory asset, of which $274 million and $174 million, respectively, represents construction work in progress (See Note 4A). Of the total $276 million of nuclear-related costs at December 31, 2009, $275 million related to Levy. The total $190 million of nuclear-related costs at December 31, 2008, was comprised of $181 million related to Levy and $9 million related to the CR3 uprate.

CR3 Uprate

On August 28, 2009, PEF filed a petition with the FPSC to approve a $17 million base rate increase for the phase II costs associated with the uprate of CR3. PEF's 2009 revenue requirements for recovery of the phase II costs were included in the CCRC. As permitted under the nuclear cost-recovery rule, PEF's phase III costs associated with the CR3 uprate are currently being recovered through the CCRC discussed above. On October 29, 2009, the FPSC Staff recommended that the FPSC approve PEF's request with minor modifications and that the new rates be implemented at the same time as PEF implements new base rates from its rate case proceeding. On October 30, 2009, PEF filed an amended petition requesting this rate change be implemented effective January 1, 2010. On December 1, 2009, the FPSC approved an increase in base rates for residential customers by $0.57 per 1,000 kWh, or 0.4 percent.

STORM COST RECOVERY

In 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007, PEF recorded the remaining amortization of $75 million associated with the recovery of these storm costs.

During 2006, the FPSC approved a settlement agreement between PEF and certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period that began August 2007 to replenish its storm reserve. Additionally, the settlement agreement provided that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. The surcharge agreement expired in August 2008. At December 31, 2009 and 2008, PEF's storm reserve totaled $136 million and $129 million, respectively.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on January 1, 2008. On May 15, 2009, PEF filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $2 million. In addition, one of PEF's large wholesale customers became subject to the new rate structure on September 1, 2009, increasing PEF's 2009 revenues by an additional $4 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense and the authorization to charge $33 million in estimated 2009 storm hardening expenses to its storm damage reserve. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC denied PEF's request related to the storm hardening expenses, but approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense will not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015.

D. Nuclear License Renewals

PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year renewal from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. At December 31, 2009 and 2008, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. We perform our annual impairment test as of April 1 of each year. During the second quarter in 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired.

9. EQUITY

A. Common Stock

At December 31, 2009 and 2008, we had 500 million shares of common stock authorized under our charter, of which 281 million shares and 264 million shares, respectively, were outstanding. For the years ended December 31, 2009, 2008 and 2007, we issued shares of common stock, primarily under a public offering and to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Progress Energy Investor Plus Plan (IPP). In addition, we periodically issue shares for our other benefit plans.

The following table presents information for our common stock issuances during the years ended December 31:

(in millions)	2009 Shares	2009 Net Proceeds	2008 Shares	2008 Net Proceeds	2007 Shares	2007 Net Proceeds
Total issuances	**17.5**	**$623**	3.7	$132	3.7	$151
Issuances under a public offering	**14.4**	**523**	–	–	–	–
Issuances to meet requirements of 401(k) and IPP	**2.5**	**100**	3.1	131	1.0	46

The shares issued under a public offering were issued on January 12, 2009, at a public offering price of $37.50. We used $100 million of the proceeds to reduce the Parent's revolving credit agreement (RCA) borrowings and the remainder was used for general corporate purposes.

Subsequent to December 31, 2009, the Parent issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings (See Note 11B).

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2009 and 2008, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has a matching feature, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 0.5 million and 1.1 million ESOP suspense shares at December 31, 2009 and 2008, respectively, with a fair value of $22 million and $45 million, respectively. ESOP shares allocated to plan participants totaled 13.0 million and 12.6 million at December 31, 2009 and 2008, respectively. Our matching compensation cost under the 401(k) is determined based on matching percentages as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for the matching component are typically met with shares in the same year incurred. Matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $13 million, $8 million and $23 million for the years ended December 31, 2009, 2008 and 2007, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation, which covers bargaining unit employees of PEF.

Total matching cost for both plans was approximately $41 million, $38 million and $34 million for the years ended December 31, 2009, 2008 and 2007, respectively.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan (EIP) and 2002 EIP, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to officers and employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. No stock options have been granted since 2004. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

A summary of the status of our stock options at December 31, 2009, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	1.6	$43.99
Canceled	(0.1)	43.76
Exercised	–	–
Options outstanding, December 31	1.5	44.00
Options exercisable, December 31	1.5	44.00

The options outstanding and exercisable at December 31, 2009, had a weighted-average remaining contractual life of 3.03 years. Aggregate intrinsic value as of December 31, 2009, was not significant. The total intrinsic value of options exercised during the years ended December 31, 2009 and 2008, was not significant. Total intrinsic value of options exercised during the year ended December 31, 2007, was $17 million.

Compensation cost for expense purposes is measured at the grant date based on the fair value of the award and is recognized over the vesting period. All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

Cash received from the exercise of stock options totaled $105 million during the year ended December 31, 2007. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2007, was $6 million. Cash received from the exercise of stock options for the years ended December 31, 2009 and 2008, was not significant.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. Our long-term compensation program currently includes two types of equity-based incentives: performance shares under the Performance Share Sub Plan (PSSP) and restricted stock programs. The compensation program was established pursuant to our 1997 EIP and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. In 2009, the PSSP was redesigned again, and shares issued under the revised plan use total shareholder return and earnings growth as two equally weighted performance measures. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities paid in the years ended December 31, 2009, 2008 and 2007, were not significant.

A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2009, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares[a]	Weighted-Average Grant Date Fair Value
Beginning balance	1,118,604	$46.46
Granted	328,369	33.80
Vested	(419,366)	44.23
Paid[b]	(232,793)	50.55
Forfeited	(16,484)	44.27
Ending balance	778,330	45.49

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.
[b] Shares paid include only target shares as originally granted.

For the years ended December 31, 2008 and 2007, the weighted-average grant date fair value of stock-settled performance shares granted was $42.41 and $50.70, respectively.

The Restricted Stock Award program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are included as shares outstanding in the basic earnings per share calculation.

A summary of the status of the nonvested restricted stock shares at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	192,101	$43.93
Granted	–	–
Vested	(50,297)	44.06
Forfeited	(6,500)	42.79
Ending balance	135,304	43.94

For the year ended December 31, 2007, the weighted-average grant date fair value of restricted stock granted was $49.54. There were no restricted stock shares granted in 2008.

The total fair value of restricted stock awards vested during the years ended December 31, 2009, 2008 and 2007, was $2 million, $3 million and $13 million, respectively. No cash was expended to purchase shares for 2009, and cash expended to purchase shares during 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program upon the rollout of the restricted stock unit (RSU) program in 2007.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are included as shares outstanding in the basic earnings per share calculation. Units are converted to shares upon vesting.

A summary of the status of nonvested RSUs at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	1,076,536	$46.86
Granted	644,231	33.91
Vested	(342,723)	47.18
Forfeited	(39,759)	41.54
Ending balance	1,338,285	43.46

The total fair value of RSUs vested during the year ended December 31, 2009, was $16 million. No cash was expended to purchase stock to satisfy RSU plan obligations in 2009, 2008 and 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $39 million for the year ended December 31, 2009, with a recognized tax benefit of $15 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $31 million, with a recognized tax benefit of $12 million, and $64 million, with a recognized tax benefit of $24 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2009, there was $31 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 1.56 years.

C. Earnings Per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of performance share awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	**2009**	2008	2007
Weighted-average common shares – basic	**279.4**	261.6	257.3
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.2
Weighted-average shares – fully diluted	**279.5**	261.7	257.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average ESOP shares totaled 0.7 million, 1.2 million and 1.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. There were 1.5 million, 1.6 million and 0.1 million stock options outstanding at December 31, 2009, 2008 and 2007, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive (Loss) Income

Components of accumulated other comprehensive (loss) income, net of tax, at December 31 were as follows:

(in millions)	**2009**	2008
(Loss) gain on cash flow hedges	**$(35)**	$(57)
Pension and other postretirement benefits	**(52)**	(58)
Other	–	(1)
Total accumulated other comprehensive (loss) income	**$(87)**	$(116)

10. PREFERRED STOCK OF SUBSIDIARIES

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

At December 31, 2009 and 2008, preferred stock outstanding consisted of the following:

(dollars in millions, except share and per share data)	Shares Authorized	Shares Outstanding	Redemption Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

11. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2009):

(in millions)		2009	2008
Parent			
Senior unsecured notes, maturing 2010-2039	6.50%	**$4,300**	$2,600
Draws on revolving credit agreement, expiring 2012		**–**	100
Unamortized premium and discount, net		**(7)**	(4)
Current portion of long-term debt		**(100)**	–
Long-term debt, net		**4,193**	2,696
PEC			
First mortgage bonds, maturing 2010-2038	5.60%	**2,525**	2,325
Pollution control obligations, maturing 2017-2024	0.80%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Miscellaneous notes	6.01%	**21**	22
Unamortized premium and discount, net		**(6)**	(7)
Current portion of long-term debt		**(6)**	–
Long-term debt, net		**3,703**	3,509
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	**3,800**	3,800
Pollution control obligations, maturing 2018-2027	0.47%	**241**	241
Medium-term notes, maturing 2028	6.75%	**150**	150
Unamortized premium and discount, net		**(8)**	(9)
Current portion of long-term debt		**(300)**	–
Long-term debt, net		**3,883**	4,182
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(37)**	(37)
Long-term debt, net		**272**	272
Progress Energy consolidated long-term debt, net		**$12,051**	$10,659

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

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

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

On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to prefund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the following table, $100 million of which was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

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

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. Fees and interest rates under Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2/Watch Negative by Moody's Investors Service, Inc. (Moody's) and BBB/Watch Negative by Standard & Poor's Rating Service (S&P). Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB+/Watch Negative by S&P. Fees and interest rates under PEF's RCA are based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

The following table summarizes short-term debt comprised of the short-term portion of outstanding RCA borrowings and our outstanding commercial paper, and related weighted-average interest rates at December 31:

(in millions)	**2009**		2008	
Parent	**0.49%**	**$140**	2.81%	$569
PEC	**–**	**–**	4.36%	110
PEF	**–**	**–**	4.41%	371
Total	**0.49%**	**$140**	3.54%	$1,050

(in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
2009					
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$–**	**$177**	**$1,853**
2008					
Parent	Five-year (expiring 5/3/12)	$1,130	$600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$600	$580	$850

[a] The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.
[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper balance with proceeds from the $950 million November 2009 issuance of Senior Notes.

The following table presents the aggregate maturities of long-term debt at December 31, 2009:

(in millions)	
2010	$406
2011	1,000
2012	950
2013	825
2014	300
Thereafter	9,034
Total	$12,515

B. Covenants and Default Provisions

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2009, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	58%
PEC	65%	44%
PEF	65%	51%

[a] Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for the Parent and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or other affiliates of PEC and PEF.

Additionally, certain of the Parent's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2009, the Parent had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by the Parent's subsidiaries as outlined below.

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2009, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2009, PEC's common stock equity was approximately 55.3 percent of total capitalization. At December 31, 2009, none of PEC's cash dividends or distributions on common stock was restricted.

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2009, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2009, PEF's common stock equity was approximately 53.4 percent of total capitalization. At December 31, 2009, none of PEF's cash dividends or distributions on common stock was restricted.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2009, PEC and PEF had a total of \$3.194 billion and \$4.041 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 18 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. Hedging Activities

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 17 for a discussion of risk management activities and derivative transactions.

12. INVESTMENTS

A. Investments

At December 31, 2009 and 2008, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

(in millions)	**2009**	2008
Nuclear decommissioning trust (See Notes 4C and 13)	**\$1,367**	\$1,089
Equity method investments[a]	**18**	22
Cost investments[b]	**5**	7
Company-owned life insurance[c]	**45**	49
Benefit investment trusts[d]	**191**	184
Marketable debt securities	**–**	1
Total	**\$1,626**	\$1,352

[a] Investments in unconsolidated companies are accounted for using the equity method of accounting (See Note 1) and are included in miscellaneous other property and investments in the Consolidated Balance Sheets. These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis.
[b] Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
[c] Investments in company-owned life insurance approximate fair value due to the nature of the investment and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
[d] Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2009 and 2008, \$152 million and \$142 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts.

B. Impairment of Investments

We evaluate declines in value of investments under the criteria of GAAP. Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts, other available-for-sale securities and equity and cost method investments. See Note 13 for additional information. There were no material other-than-temporary impairments in 2009, 2008 or 2007.

13. FAIR VALUE DISCLOSURES

A. Debt and Investments

DEBT

The carrying amount of our long-term debt, including current maturities, was \$12.457 billion and \$10.659 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $13.4 billion and $11.3 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

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

The following table summarizes our available-for-sale securities at December 31, 2009 and 2008.

(in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
2009			
Equity securities	**$(22)**	**$306**	**$855**
Corporate debt securities	**(1)**	**5**	**71**
U.S. state and municipal debt securities	**(2)**	**3**	**118**
U.S. and foreign government debt securities	**(1)**	**8**	**197**
Money market funds and other securities	**–**	**–**	**161**
Total	**$(26)**	**$322**	**$1,402**
2008			
Equity securities	$(93)	$134	$559
Corporate debt securities	(5)	–	53
U.S. state and municipal debt securities	(19)	4	233
U.S. and foreign government debt securities	(2)	11	171
Money market funds and other securities	(1)	–	123
Total	$(120)	$149	$1,139

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments; all of the unrealized losses and unrealized gains for 2009, and $118 million of the unrealized losses and $148 million of the unrealized gains for 2008, relate to the NDT funds. There were no material unrealized losses for the other available-for-sale debt securities held in benefit trusts at December 31, 2009 and 2008.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $209 million and $374 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$12
Due after one through five years	180
Due after five through 10 years	122
Due after 10 years	84
Total	$398

The following table presents selected information about our sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2009**	2008	2007
Proceeds	**$1,275**	$1,092	$1,334
Realized gains	**26**	29	35
Realized losses	**87**	86	23

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, our proceeds from the sale of these securities were $399 million. For the years ended December 31, 2009 and 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2009, 2008 and 2007 for investments in these benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2009 and 2008, our other securities had no investments in a continuous loss position for greater than 12 months.

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 table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$855	$–	$–	$855
Corporate debt	–	71	–	71
U.S. state and municipal debt	–	117	–	117
U.S. and foreign government debt	62	128	–	190
Money market funds and other	1	133	–	134
Total nuclear decommissioning trust funds	918	449	–	1,367
Commodity and interest rate derivatives	–	39	–	39
Other marketable securities				
U.S. state and municipal debt	–	1	–	1
U.S. and foreign government debt	–	7	–	7
Money market funds and other	16	27	–	43
Total assets	$934	$523	$–	$1,457
Liabilities				
Commodity and interest rate derivatives	$–	$(386)	$(39)	$(425)
CVO derivatives	–	(15)	–	(15)
Total liabilities	$–	$(401)	$(39)	$(440)

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

Commodity and interest rate derivatives reflect positions held by us. Most over-the-counter commodity and interest rate derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 17 for discussion of risk management activities and derivative transactions.

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

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

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

The following table sets forth a reconciliation of changes in the fair value of our commodity derivatives classified as Level 3 in the fair value hierarchy for the 12 months ended December 31, 2009.

(in millions)	
Derivatives, net at January 1, 2009	$(41)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(13)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	15
Derivatives, net at December 31, 2009	$(39)

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

Transfers in (out) of Level 3 represent existing assets or liabilities that were previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Transfers into Level 3 are measured at the beginning of the period, and transfers out of Level 3 are measured at the end of the period.

14. INCOME TAXES

We provide deferred income taxes for temporary differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	2009	2008
Deferred income tax assets		
ARO liability	**$127**	$264
Derivative instruments	**159**	298
Income taxes refundable through future rates	**225**	111
Pension and other postretirement benefits	**508**	544
Other	**374**	340
Federal income tax credit carry forward	**712**	802
State net operating loss carry forward (net of federal expense)	**66**	64
Valuation allowance	**(55)**	(55)
Total deferred income tax assets	**2,116**	2,368
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,889)**	(1,665)
Deferred fuel recovery	**(74)**	(186)
Income taxes recoverable through future rates	**(782)**	(959)
Other	**(264)**	(141)
Total deferred income tax liabilities	**(3,009)**	(2,951)
Total net deferred income tax liabilities	**$(893)**	$(583)

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

(in millions)	2009	2008
Current deferred income tax assets, included in prepayments and other current assets	**$168**	$96
Noncurrent deferred income tax assets, included in other assets and deferred debits	**37**	32
Current deferred income tax liabilities, included in other current liabilities	**–**	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,098)**	(710)
Total net deferred income tax liabilities	**$(893)**	$(583)

At December 31, 2009, the federal income tax credit carry forward includes $712 million of alternative minimum tax credits that do not expire.

At December 31, 2009, we had gross state net operating loss carry forwards of $1.6 billion that will expire during the period 2010 through 2029.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of less than $1 million in our valuation allowances during 2009.

We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

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

	2009	2008	2007
Effective income tax rate	**32.1%**	33.7%	32.3%
State income taxes, net of federal benefit	**(3.7)**	(3.8)	(2.8)
Investment tax credit amortization	**0.8**	1.0	1.1
Employee stock ownership plan dividends	**1.0**	1.0	1.1
Domestic manufacturing deduction	**0.8**	0.3	1.0
AFUDC equity	**2.2**	2.5	0.7
Other differences, net	**1.8**	0.3	1.6
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	2009	2008	2007
Current – federal	**$227**	$38	$285
– state	**41**	12	36
Deferred – federal	**114**	305	13
– state	**25**	49	11
Investment tax credit	**(10)**	(12)	(12)
State net operating loss carry forward	**–**	(6)	1
Beginning-of-the-year valuation allowance change	**–**	9	–
Total income tax expense	**$397**	$395	$334

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

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

- Taxes related to discontinued operations recorded net of tax for 2009, 2008 and 2007, which are presented separately in Notes 3A through 3E.
- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock

awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2009 and 2008.

- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

At December 31, 2009, 2008 and 2007, our liability for unrecognized tax benefits was $160 million, $104 million and $93 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $9 million, $8 million and $10 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	**2009**	2008	2007
Unrecognized tax benefits at beginning of period	**$104**	$93	$126
Gross amounts of increases as a result of tax positions taken in a prior period	**11**	17	32
Gross amounts of decreases as a result of tax positions taken in a prior period	**(3)**	(11)	(41)
Gross amounts of increases as a result of tax positions taken in the current period	**52**	8	22
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(2)	(32)
Amounts of net increases (decreases) relating to settlements with taxing authorities	**–**	1	(14)
Reductions as a result of a lapse of the applicable statute of limitations	**–**	(2)	–
Unrecognized tax benefits at end of period	**$160**	$104	$93

We file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our open federal tax years are from 2004 forward, and our open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2009, 2008 and 2007, the net interest expense related to unrecognized tax benefits was $9 million, $4 million and $1 million, respectively, of which a respective $5 million, $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2009 and 2007, there were no penalties related to unrecognized tax benefits. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. At December 31, 2009 and 2008, we had accrued $36 million and $27 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, three of which were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 3A). The payments are based on the net after-tax cash flows the facilities generate. We will make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. Monies held in the trust are generally not payable to the CVO holders until the completion of income tax audits. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively.

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuels facilities (See Note 3E). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2009 and 2008 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheets at December 31, 2009 and 2008.

16. BENEFIT PLANS

A. Postretirement Benefits

We have noncontributory defined benefit retirement plans that provide pension benefits for substantially all full-time employees. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

COSTS OF BENEFIT PLANS

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of the pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

The table below provides the components of the net periodic benefit cost for 2009, 2008 and 2007. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$42**	$46	$46	**$7**	$8	$7
Interest cost	**138**	128	123	**31**	34	32
Expected return on plan assets	**(133)**	(170)	(155)	**(4)**	(6)	(6)
Amortization of actuarial loss[a]	**54**	8	15	**1**	1	2
Other amortization, net[a]	**6**	2	2	**5**	5	5
Net periodic cost before deferral[b]	**$107**	$14	$31	**$40**	$42	$40

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

[b] In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (See Note 7C).

The following table provides a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income, for 2009, 2008 and 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$(1)**	$(64)	$24	**$4**	$(8)	$16
Other, net	**–**	(6)	(1)	**–**	–	–
Reclassification adjustments						
Net actuarial loss	**5**	1	2	**1**	–	–
Other, net	**–**	1	1	**1**	–	–
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	**10**	(735)	66	**64**	(73)	82
Other, net	**(3)**	(36)	(8)	**–**	–	–
Amortized to income[a]						
Net actuarial loss	**49**	7	13	**–**	1	2
Other, net	**6**	1	1	**4**	5	4

[a] These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

The following weighted-average actuarial assumptions were used in the calculation of our net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Discount rate	**6.30%**	6.20%	5.95%	**6.20%**	6.20%	5.95%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	4.25%	**–**	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	**–**	–	–
Expected long-term rate of return on plan assets	**8.75%**	9.00%	9.00%	**6.80%**	8.10%	7.70%

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans' target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2009, primarily due to the uncertainties resulting from the severe capital market deterioration in 2008. See the "Assets of Benefit Plans" section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in benefit obligations and the funded status as of December 31, 2009 and 2008, are presented in the table below, followed by related supplementary information.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$2,234**	$2,142	**$608**	$541
Service cost	**42**	46	**7**	8
Interest cost	**138**	128	**31**	34
Settlements	**(9)**	–	**–**	–
Benefit payments	**(124)**	(127)	**(40)**	(35)
Plan amendment	**3**	42	**–**	–
Actuarial loss (gain)	**138**	3	**(63)**	60
Obligation at December 31	**2,422**	2,234	**543**	608
Fair value of plan assets at December 31	**1,673**	1,285	**55**	52
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.422 billion and $2.234 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $2.378 billion and $2.196 billion at December 31, 2009 and 2008, respectively, and plan assets of $1.673 billion and $1.285 billion at December 31, 2009 and 2008, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Current liabilities	**$(9)**	$(10)	**$–**	$(1)
Noncurrent liabilities	**(740)**	(939)	**(488)**	(555)
Funded status	**$(749)**	$(949)	**$(488)**	$(556)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$83**	$87	**$(5)**	$–
Other, net	**10**	11	**–**	–
Recognized in regulatory assets, net				
Net actuarial loss	**806**	865	**32**	97
Other, net	**59**	62	**14**	18
Total not yet recognized as a component of net periodic cost[a]	**$958**	$1,025	**$41**	$115

[a] All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$50	$1
Amortization of other, net[a]	6	5

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

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	**2009**	2008
Discount rate	**6.00%**	6.30%	**6.05%**	6.20%
Rate of increase in future compensation				
Bargaining	**4.50%**	4.25%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**8.50%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**8.50%**	9.00%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2016**	2016

The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan. Therefore, we use the traditional unit credit method for purposes of measuring the benefit obligation of this plan.

Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$2
Effect on postretirement benefit obligation	26
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(1)
Effect on postretirement benefit obligation	(21)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation table that follows, our employer contributions for 2009 and 2008 include contributions directly to pension plan assets of $222 million and $33 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from our assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2009 and 2008, the subsidies totaled $3 million.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$1,285**	$1,996	**$52**	$75
Actual return on plan assets	**279**	(627)	**9**	(16)
Benefit payments, including settlements	**(133)**	(127)	**(40)**	(35)
Employer contributions	**242**	43	**34**	28
Fair value of plan assets at December 31	**$1,673**	$1,285	**$55**	$52

Our primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rolling 10-year annual return of 6 percent over the rate of inflation. The target pension asset allocations are 40 percent domestic equity, 20 percent international equity, 10 percent domestic fixed income, 15 percent global fixed income, 10 percent private equity and timber and 5 percent hedge funds. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth based investment strategies. Domestic fixed income primarily includes domestic investment grade fixed income investments. Global fixed income includes domestic and foreign fixed income investments. A substantial portion of OPEB plan assets are managed with pension assets. The remaining OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

The following table sets forth by level within the fair value hierarchy of our pension and other postretirement plan assets as of December 31, 2009. See Note 13 for detailed information regarding the fair value hierarchy.

(in millions)	Pension Benefit Plan Assets Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$1	$96	$–	$97
Domestic equity securities	263	1	–	264
Private equity securities	–	–	122	122
Corporate bonds	–	67	–	67
U.S. state and municipal debt	–	4	–	4
U.S. and foreign government debt	25	95	–	120
Mortgage backed securities	–	22	–	22
Commingled funds	–	888	–	888
Hedge funds	–	47	2	49
Timber investments	–	–	14	14
Credit default swaps	–	20	–	20
Interest rate swaps and other investments	–	36	–	36
Total assets	$289	$1,276	$138	$1,703
Liabilities				
Foreign currency contracts	(5)	–	–	(5)
Credit default swaps	–	(20)	–	(20)
Interest rate swaps and other investments	–	(5)	–	(5)
Total liabilities	(5)	(25)	–	(30)
Fair value of plan assets	$284	$1,251	$138	$1,673

(in millions)	Other Postretirement Benefit Plan Assets Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$–	$1	$–	$1
Domestic equity securities	4	–	–	4
Corporate bonds	–	1	–	1
U.S. state and municipal debt	–	32	–	32
U.S. and foreign government debt	–	2	–	2
Commingled funds	–	13	–	13
Hedge funds	–	1	–	1
Interest rate swaps and other investments	–	1	–	1
Fair value of plan assets	$4	$51	$–	$55

The following table sets forth a reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$111	$2	$18	$131
Net realized and unrealized (losses)[a]	(10)	–	(4)	(14)
Purchases, sales and distributions, net	21	–	–	21
Balance at December 31	$122	$2	$14	$138

[a] Substantially all amounts relate to investments held at December 31, 2009.

The determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments.

Investments in commingled funds are not publicly traded, but the underlying assets held in these funds are traded in active markets and the prices for the assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2010, we expect to make $120 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $158, $161, $167, $170, $178 and $961, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $37, $40, $42, $45, $46 and $251, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $4, $4, $5, $5, $6 and $40, respectively.

B. Florida Progress Acquisition

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

A. Commodity Derivatives

GENERAL

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

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary PVI sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations was included in discontinued operations on the Consolidated Statements of Income.

In 2007, we entered into derivative contracts to hedge economically a portion of our synthetic fuels cash flow exposure to the risk of rising oil prices. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash in January 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed in Note 3E, we disposed of our 100 percent ownership interest in Ceredo in March 2007. Progress Energy is the primary beneficiary of, and continues to consolidate, Ceredo in accordance with GAAP for variable interest entities, but we have recorded a 100 percent noncontrolling interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007.

During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo, $42 million of which was attributed to noncontrolling interest for the portion of the gain subsequent to the disposal of Ceredo.

ECONOMIC DERIVATIVES

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

The Utilities have derivative instruments through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2010 and 2011. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Consolidated Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

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

Certain counterparties have held cash collateral from PEC in support of these instruments. PEC had a $7 million and an $18 million cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheets at December 31, 2009 and 2008, respectively. At December 31, 2009, PEC had 50.3 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted PEF's cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheets, which was $139 million at December 31, 2009, compared to $335 million at December 31, 2008. At December 31, 2009, PEF had 182.4 million MMBtu notional of natural gas and 56.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. At December 31, 2009, we had 0.4 million gallons notional of gasoline and 0.5 million gallons notional of heating oil related to outstanding commodity derivative swaps at PEC and at PEF that were entered into to hedge forecasted gasoline and diesel purchases. Realized gains and losses are recorded net as part of fleet vehicle fuel costs. At December 31, 2009 and 2008, we did not have material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2009, 2008 and 2007.

At December 31, 2009 and 2008, the amount recorded in our accumulated other comprehensive income related to commodity cash flow hedges was not material.

B. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

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

CASH FLOW HEDGES

At December 31, 2009, all open forward starting swaps will reach their mandatory termination dates within three years. At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses recorded in accumulated other comprehensive income related to interest cash flow hedges. It is expected that in the next 12 months losses of $7 million, net of tax, will be reclassified to interest expense. The actual amount that will be reclassified to earnings may vary from the expected amount as a result of the timing of debt issuances and changes in market value of currently open forward starting swaps.

At December 31, 2008, including amounts related to terminated hedges, we had $56 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2007, including amounts related to terminated hedges, we had $24 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, we had $325 million notional of open forward starting swaps. At December 31, 2008, we had $450 million notional of open forward starting swaps. During January 2010, we entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2009 and 2008, we did not have any outstanding positions in such contracts.

C. Contingent Features

Certain of our derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with each of the major credit rating agencies. Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

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

The aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a liability position at December 31, 2009, was $405 million, for which we had posted collateral of $146 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, we would have been required to post an additional $260 million of collateral with our counterparties.

D. Derivative Instrument and Hedging Activity Information

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument/Balance sheet location (in millions)	December 31, 2009 Asset	December 31, 2009 Liability	December 31, 2008 Asset	December 31, 2008 Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		**$–**		$(2)
Interest rate derivatives				
Prepayments and other current assets	**$5**		$–	
Other assets and deferred debits	**14**		–	
Derivative liabilities, current		**–**		(65)
Total derivatives designated as hedging instruments	**19**	**–**	–	(67)
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	**11**		9	
Other assets and deferred debits	**9**		1	
Derivative liabilities, current		**(189)**		(425)
Derivative liabilities, long-term		**(236)**		(263)
CVOs[b]				
Other liabilities and deferred credits		**(15)**		(34)
Fair value of derivatives not designated as hedging instruments	**20**	**(440)**	10	(722)
Fair value loss transition adjustment[c]				
Derivative liabilities, current		**(1)**		(1)
Derivative liabilities, long-term		**(4)**		(6)
Total derivatives not designated as hedging instruments	**20**	**(445)**	10	(729)
Total derivatives	**$39**	**$(445)**	$10	$(796)

[a] Substantially all of these contracts receive regulatory treatment.
[b] The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000 (See Note 15).
[c] In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a] 2009	2008	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a] 2009	2008	Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b] 2009	2008
Commodity cash flow derivatives	**$1**	$(2)		**$–**	$–		**$–**	$–
Interest rate derivatives[c]	**15**	(35)	Interest charges	**(6)**	(3)	Interest charges	**(3)**	1

[a] Effective portion.
[b] Related to ineffective portion and amount excluded from effectiveness testing.
[c] Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments				
Instrument	Realized Gain or (Loss)[a]		Unrealized Gain or (Loss)[b]	
(in millions)	**2009**	2008	**2009**	2008
Commodity derivatives	**$(659)**	$174	**$(387)**	$(653)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
(in millions)		**2009**	2008
Commodity derivatives	Other, net	**$1**	$(3)
Fair value loss transition adjustment	Other, net	**2**	3
CVOs	Other, net	**19**	–
Total		**$22**	$–

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2009, the Parent had issued $391 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheets.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935. The repeal of the Public Utility Holding Company Act of 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered.

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

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

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

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments. Operational results and assets to be divested are not included in the table presented below.

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Total
At and for the year ended December 31, 2009					
Revenues					
Unaffiliated	**$4,627**	**$5,249**	**$9**	**$–**	**$9,885**
Intersegment	**–**	**2**	**234**	**(236)**	**–**
Total revenues	**4,627**	**5,251**	**243**	**(236)**	**9,885**
Depreciation, amortization and accretion	**470**	**502**	**14**	**–**	**986**
Interest income	**5**	**4**	**38**	**(33)**	**14**
Total interest charges, net	**195**	**231**	**286**	**(33)**	**679**
Income tax expense (benefit)[(a)]	**294**	**209**	**(87)**	**–**	**416**
Ongoing Earnings (loss)	**540**	**460**	**(154)**	**–**	**846**
Total assets	**13,502**	**13,100**	**20,538**	**(15,904)**	**31,236**
Capital and investment expenditures	**962**	**1,532**	**21**	**(12)**	**2,503**
At and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$–	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Ongoing Earnings (loss)	531	383	(138)	–	776
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560
At and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$4,385	$4,748	$20	$–	$9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation, amortization and accretion	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Ongoing Earnings (loss)	498	315	(118)	–	695
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204

[(a)] Income tax expense (benefit) for 2009 excludes tax impact of $17 million benefit at PEC and $1 million benefit at Corporate and Other for Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. A reconciliation of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended 2009, 2008 and 2007, respectively, is as follows:

(in millions)	**2009**	2008	2007
Ongoing Earnings	**$846**	$776	$695
CVO mark-to-market	**19**	–	(2)
Impairment, net of tax benefit of $1	**(2)**	–	–
Plant retirement charge, net of tax benefit of $11	**(17)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $6 (See Note 24)	**(10)**	–	–
Valuation allowance and related net operating loss carry forward	–	(3)	–
Continuing income attributable to noncontrolling interests, net of tax	**4**	5	9
Income from continuing operations	**840**	778	702
Discontinued operations, net of tax	**(79)**	58	(206)
Net income attributable to noncontrolling interests, net of tax	**(4)**	(6)	8
Net income attributable to controlling interests	**$757**	$830	$504

20. OTHER INCOME AND EXPENSE

Other income and expense includes interest income; AFUDC equity, which represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets; and other, net. The components of other, net as shown on the accompanying Consolidated Statements of Income are presented below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities.

(in millions)	**2009**	2008	2007
Nonregulated energy and delivery services income, net	**$17**	$17	$12
Fair value loss transition adjustment amortization (Note 17D)	**2**	3	4
CVO unrealized gain (loss), net (Note 15)	**19**	–	(2)
Donations	**(20)**	(25)	(22)
Other, net	**(12)**	(12)	1
Other, net	**$6**	$(17)	$(7)

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

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

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

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other current liabilities and other liabilities and deferred credits on the Consolidated Balance Sheets, at December 31 were:

(in millions)	**2009**	2008
PEC		
MGP and other sites[a]	**$13**	$16
PEF		
Remediation of distribution and substation transformers	**20**	22
MGP and other sites	**9**	15
Total PEF environmental remediation accruals[b]	**29**	37
Total Progress Energy environmental remediation accruals	**$42**	$53

[a] Expected to be paid out over one to five years.
[b] Expected to be paid out over one to 15 years.

Including PEC's Ward Transformer site located in Raleigh, N.C. (Ward), PEF's distribution and substation transformers sites, and the Utilities' MGP sites discussed below, for the year ended December 31, 2009, we accrued approximately $16 million and spent approximately $27 million. For the year ended December 31, 2008, we accrued approximately $25 million and spent approximately $36 million. For the year ended December 31, 2007, we accrued approximately $8 million and spent approximately $27 million.

In addition to these sites, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2009 and 2008, PEC's recorded liability for the site was approximately $4 million and $7 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed an initial civil action against a number of PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. On March 13, 2009, a subsequent action was filed against additional PRPs, and on April 30, 2009, suit was filed against the remaining approximately 160 PRPs. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. With respect to the defendants that do not settle, the federal district court in which this matter is pending requires that alternative dispute resolution be pursued early in civil litigation but it is unclear what process the court will require. The outcome of these matters cannot be predicted.

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

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC. For the year ended December 31, 2009, PEF accrued approximately $13 million due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $15 million related to the remediation of transformers. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. At December 31, 2009 and 2008, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

B. Air and Water Quality

At December 31, 2009 and 2008, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act, enacted in June 2002 and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2009, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $2.119 billion, including $1.054 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $1.065 billion at PEF, which related entirely to in-process CAIR projects. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, in response to petitions for rehearing filed by a number of parties, the D.C. Court of Appeals remanded the CAIR without vacating the rule for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. Because the D.C. Court of Appeals December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions 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. The three states in which the Utilities operate adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. Under an agreement with the FDEP, PEF will retire CR1 and CR2 as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. As discussed under "Other Matters – Nuclear," PEF expects the schedule for the commercial operation of Levy to shift later than the 2016 to 2018 timeframe by a minimum of 20 months. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. PEF has advised the FDEP of a Levy schedule shift. We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. At December 31, 2009 and 2008, PEC had approximately \$13 million and \$22 million, respectively, in SO_2 emission allowances and an immaterial amount of NOx emission allowances. At December 31, 2009 and 2008, PEF had approximately \$7 million and \$11 million, respectively, in SO_2 emission allowances and approximately \$36 million and \$65 million, respectively, in NOx emission allowances.

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, in 2005 PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately \$38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. All of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, have been placed in service and PEC estimates its remaining exposure is not material. See Note 22C for further discussion of PEC's indemnification liability. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of \$584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service.

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2009, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	\$2,647	\$2,335	\$1,953	\$1,706	\$1,405	\$8,217
Purchased power	445	467	447	445	367	3,636
Construction obligations	1,820	1,725	1,453	1,524	1,313	1,543
Other purchase obligations	52	74	36	27	19	163
Total	\$4,964	\$4,601	\$3,889	\$3,702	\$3,104	\$13,559

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our payments under these commitments were \$2.921 billion, \$3.078 billion and \$2.360 billion for 2009, 2008 and 2007, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are recovered through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units. (See discussion under Construction Obligations below.) This $334 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2010 to 2029. These purchased power contracts generally provide for capacity and energy payments.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility. One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $24 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $24 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River LLC's Broad River facility agreements amounted to $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $12 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2029. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $24 million, $55 million and $95 million in 2009, 2008 and 2007, respectively.

PEF has firm contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (12 percent of net output) of purchased power that ends in 2010. Additional contracts with Southern Company for approximately 424 MW (25 percent of net output) of purchased power annually start in 2010 and extend through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $149 million, $178 million and $161 million for 2009, 2008 and 2007, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million, $56 million, $44 million, $52 million and $52 million for 2010 through 2014, respectively, and $74 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2010 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity and energy payments made under these contracts amounted to $435 million, $440 million and $447 million for 2009, 2008 and 2007, respectively. Minimum expected future capacity payments under these contracts are $286 million, $301 million, $313 million, $310 million and $237 million for 2010 through 2014, respectively, and $3.042 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In 2009, PEC executed a long-term coal transportation agreement by combining, amending and restating previous agreements with Norfolk Southern Railroad. This agreement will support PEC's coal supply needs through June 2020. Expected future transportation payments under this agreement are $254 million, $264 million, $260 million, $254 million and $277 million for 2010 through 2014, respectively, with approximately $1.679 billion payable thereafter. Coal transportation expenses under these agreements were approximately $283 million in 2009. PEC's state utility commissions allow fuel-related costs to be recovered through fuel cost-recovery clauses.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through August 2032. The estimated total cost to PEC associated with these agreements is approximately $1.598 billion, approximately $404 million of which will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until approximately 2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in fuel commitments.

In April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.065 billion. In addition to the FGT contracts, PEF has entered into additional gas supply and transportation arrangements for the period from 2010 through 2036. The total current notional cost of these additional agreements is estimated to be approximately $1.043 billion. The FGT contracts along with the additional gas supply and transportation arrangements are subject to several conditions precedent, including various federal regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in fuel commitments.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $818 million, $1.018 billion and $698 million for 2009, 2008 and 2007, respectively. The majority of our construction obligations relate to PEF as discussed below.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $199 million, $140 million and $208 million for 2009, 2008 and 2007, respectively.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.608 billion are included for the multi-year contract and do not assume any joint ownership. The contractual obligations presented are in accordance with the existing terms of the EPC agreement. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance resulting in a minimum 20-month in-service schedule shift for the Levy units from the original 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in construction obligations. See Note 7C for additional information about the Levy project. PEF made payments of $243 million and $117 million in 2009 and 2008, respectively, toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $376 million, $761 million and $490 million for 2009, 2008 and 2007, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $56 million, $110 million and $75 million for 2009, 2008 and 2007, respectively.

PEC has various purchase obligations, including obligations for limestone supply and fleet vehicles. Total purchases under these contracts were $14 million, $18 million and $6 million for 2009, 2008 and 2007, respectively.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow Plant, emission obligations and fleet vehicles. Total payments under these contracts were $22 million, $58 million and $24 million for 2009, 2008 and 2007, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $37 million, $38 million and $40 million for 2009, 2008 and 2007, respectively. Our purchased power expense under agreements classified as operating leases was approximately $11 million, $152 million and $69 million in 2009, 2008 and 2007, respectively.

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

(in millions)	**2009**	2008
Buildings	**$267**	$267
Less: Accumulated amortization	**(37)**	(28)
Total	**$230**	$239

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $26 million each for 2009 and 2008 and $22 million for 2007, which was primarily comprised of PEF's capital lease expense of $24 million each for 2009 and 2008 and $20 million for 2007.

At December 31, 2009, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

(in millions)	Capital	Operating
2010	$28	$35
2011	28	29
2012	28	48
2013	36	78
2014	26	77
Thereafter	246	941
Minimum annual payments	392	$1,208
Less amount representing imputed interest	(162)	
Present value of net minimum lease payments under capital leases	$230	

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

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

In 2009, PEC entered into a 240-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $10 million from July 2012 through September 2017, for a total of approximately $52 million.

In 2007, PEF entered into a 632-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from June 2012 through May 2027, for a total of approximately $420 million.

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for minimum annual payments of approximately $5 million from 2007 through 2026, for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2006, PEF extended the terms of a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $11 million for 2010 and none thereafter. PEC's rents received are contingent upon usage and totaled $34 million for 2009 and $33 million each for 2008 and 2007. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $84 million, $81 million and $78 million for 2009, 2008 and 2007, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2010 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2009, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2009, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2009, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. At December 31, 2009 and 2008, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $34 million and $61 million, respectively. During the year ended December 31, 2009, our indemnification liability for certain legal matters made in connection with the sale of businesses decreased by approximately $16 million as a result of a legal verdict discussed under "Synthetic Fuels Matters" in Note 22D. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro Plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification. At December 31, 2009, all of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, had been placed in service. PEC estimates its remaining exposure under the indemnification is not material (See Note 21B). During the year ended December 31, 2009, PEC accrued approximately $2 million and spent approximately $12 million that exceeded the joint owner limit. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. Other Commitments and Contingencies

SPENT NUCLEAR FUEL MATTERS

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

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

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. Oral arguments were held on May 4, 2009. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000, (the Asset Purchase Agreement) by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global had requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations (See Note 3A).

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations (See Note 3A), which was net of a previously recorded indemnification liability of $16 million. In December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. On December 16, 2009, we filed notice of appeal. We cannot predict the outcome of this matter.

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

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the resolution of the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the Florida Global Case related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

NOTICE OF VIOLATION

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

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. PEF believes the lawsuit is without merit and will defend against it. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

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

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the Condensed Consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The annual interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. At December 31, 2009, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional, guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

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

In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only. 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. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$5,259	$4,626	$–	$9,885
Affiliate revenues	–	–	235	(235)	–
Total operating revenues	–	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	–	2,072	1,680	–	3,752
Purchased power	–	682	229	–	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	–	502	484	–	986
Taxes other than on income	–	347	216	(6)	557
Other	–	13	–	–	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	–	91	33	–	124
Other, net	18	6	(22)	4	6
Total other income (expense), net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	–	(27)	(12)	–	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	–	–	(875)	–
Income (loss) from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	–	(79)
Net income (loss)	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	–	(3)	2	(3)	(4)
Net income (loss) attributable to controlling interests	$757	$407	$478	$(885)	$757

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Affiliate revenues	–	–	361	(361)	–
Total operating revenues	–	4,738	4,790	(361)	9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,346	(342)	1,820
Depreciation, amortization and accretion	–	306	533	–	839
Taxes other than on income	–	309	207	(8)	508
Other	–	1	(4)	–	(3)
Total operating expenses	3	4,057	3,774	(350)	7,484
Operating (loss) income	(3)	681	1,016	(11)	1,683
Other income (expense)					
Interest income	11	9	16	(12)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	(4)	5	(17)
Total other income (expense), net	11	86	39	(7)	129
Interest charges					
Interest charges	201	263	227	(12)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	215	(12)	639
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(193)	532	840	(6)	1,173
Income tax (benefit) expense	(85)	172	306	2	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Income (loss) from continuing operations	833	360	534	(949)	778
Discontinued operations, net of tax	(3)	61	–	–	58
Net income (loss)	830	421	534	(949)	836
Net income attributable to noncontrolling interests, net of tax	–	(6)	–	–	(6)
Net income (loss) attributable to controlling interests	$830	$415	$534	$(949)	$830

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2007 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Affiliate revenues	–	–	391	(391)	–
Total operating revenues	–	4,768	4,776	(391)	9,153
Operating expenses					
Fuel used in electric generation	–	1,764	1,381	–	3,145
Purchased power	–	882	302	–	1,184
Operation and maintenance	10	834	1,369	(371)	1,842
Depreciation, amortization and accretion	–	369	536	–	905
Taxes other than on income	–	309	202	(10)	501
Other	–	20	98	(88)	30
Total operating expenses	10	4,178	3,888	(469)	7,607
Operating (loss) income	(10)	590	888	78	1,546
Other income (expense)					
Interest income	27	8	24	(25)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	(9)	4	(7)
Total other income (expense), net	27	47	25	(21)	78
Interest charges					
Interest charges	203	210	219	(27)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	214	(27)	588
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(186)	439	699	84	1,036
Income tax (benefit) expense	(79)	117	297	(1)	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Income (loss) from continuing operations	489	322	402	(511)	702
Discontinued operations, net of tax	15	13	(137)	(97)	(206)
Net income (loss)	504	335	265	(608)	496
Net loss attributable to noncontrolling interests, net of tax	–	8	–	–	8
Net income (loss) attributable to controlling interests	$504	$343	$265	$(608)	$504

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$9,733	$9,886	$114	$19,733
Current assets					
Cash and cash equivalents	606	72	47	–	725
Notes receivable from affiliated companies	30	46	303	(379)	–
Regulatory assets	–	54	88	–	142
Derivative collateral posted	–	139	7	–	146
Income taxes receivable	5	97	50	(7)	145
Prepayments and other current assets	14	1,158	1,377	(176)	2,373
Total current assets	655	1,566	1,872	(562)	3,531
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,348	–	–	(13,348)	–
Regulatory assets	–	1,307	873	(1)	2,179
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	496	871	–	1,367
Other assets and deferred debits	166	202	923	(520)	771
Total deferred debits and other assets	13,514	2,005	2,667	(10,214)	7,972
Total assets	$14,169	$13,304	$14,425	$(10,662)	$31,236
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$9,449	$4,590	$5,085	$(9,675)	$9,449
Noncontrolling interests	–	3	3	–	6
Total equity	9,449	4,593	5,088	(9,675)	9,455
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	4,193	3,883	3,703	–	11,779
Total capitalization	13,642	8,819	8,965	(9,827)	21,599
Current liabilities					
Current portion of long-term debt	100	300	6	–	406
Short-term debt	140	–	–	–	140
Notes payable to affiliated companies	–	376	3	(379)	–
Derivative liabilities	–	161	29	–	190
Other current liabilities	261	941	902	(182)	1,922
Total current liabilities	501	1,778	940	(561)	2,658
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	320	1,258	(382)	1,196
Regulatory liabilities	–	1,103	1,293	114	2,510
Other liabilities and deferred credits	26	1,284	1,969	(6)	3,273
Total deferred credits and other liabilities	26	2,707	4,520	(274)	6,979
Total capitalization and liabilities	$14,169	$13,304	$14,425	$(10,662)	$31,236

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$8,790	$9,385	$118	$18,293
Current assets					
Cash and cash equivalents	88	73	19	–	180
Notes receivable from affiliated companies	34	44	131	(209)	–
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Income taxes receivable	34	56	104	–	194
Prepayments and other current assets	14	1,082	1,336	(172)	2,260
Total current assets	170	1,916	1,815	(381)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	417	672	–	1,089
Other assets and deferred debits	155	196	953	(555)	749
Total deferred debits and other assets	12,079	1,937	2,868	(8,824)	8,060
Total assets	$12,249	$12,643	$14,068	$(9,087)	$29,873
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$8,687	$3,519	$4,729	$(8,248)	$8,687
Noncontrolling interests	–	3	4	(1)	6
Total equity	8,687	3,522	4,733	(8,249)	8,693
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	8,416	(8,401)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	3	(209)	–
Derivative liabilities	31	380	84	(2)	493
Other current liabilities	220	964	930	(171)	1,943
Total current liabilities	820	1,921	1,127	(382)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Other liabilities and deferred credits	45	1,481	2,427	(10)	3,943
Total deferred credits and other liabilities	46	2,675	4,525	(304)	6,942
Total capitalization and liabilities	$12,249	$12,643	$14,068	$(9,087)	$29,873

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$108	$1,079	$1,282	$(198)	$2,271
Investing activities					
Gross property additions	–	(1,449)	(858)	12	(2,295)
Nuclear fuel additions	–	(78)	(122)	–	(200)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	–	1	–	1
Proceeds from sales of assets to affiliated companies	–	–	11	(11)	–
Purchases of available-for-sale securities and other investments	–	(1,548)	(802)	–	(2,350)
Proceeds from available-for-sale securities and other investments	–	1,558	756	–	2,314
Changes in advances to affiliated companies	4	(2)	(172)	170	–
Contributions to consolidated subsidiaries	(688)	–	–	688	–
Return of investment in consolidated subsidiaries	12	–	–	(12)	–
Other investing activities	–	–	(2)	–	(2)
Net cash (used) provided by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock	623	–	–	–	623
Dividends paid on common stock	(693)	–	–	–	(693)
Dividends paid to parent	–	(1)	(200)	201	–
Dividends paid to parent in excess of retained earnings	–	–	(12)	12	–
Payments of short-term debt with original maturities greater than 90 days	(29)	–	–	–	(29)
Net decrease in short-term debt	(500)	(371)	(110)	–	(981)
Proceeds from issuance of long-term debt, net	1,683	–	595	–	2,278
Retirement of long-term debt	–	–	(400)	–	(400)
Cash distributions to noncontrolling interests	–	(3)	–	(3)	(6)
Changes in advances from affiliated companies	–	170	–	(170)	–
Contributions from parent	–	653	49	(702)	–
Other financing activities	(2)	(9)	12	13	14
Net cash provided (used) by financing activities	1,082	439	(66)	(649)	806
Net increase (decrease) in cash and cash equivalents	518	(1)	28	–	545
Cash and cash equivalents at beginning of year	88	73	19	–	180
Cash and cash equivalents at end of year	$606	$72	$47	$–	$725

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$(90)	$221	$1,114	($27)	$1,218
Investing activities					
Gross property additions	–	(1,553)	(794)	14	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	13	–	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(800)	–	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	746	–	1,534
Changes in advances to affiliated companies	123	105	8	(236)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Return of investment in consolidated subsidiaries	20	10	–	(30)	–
Other investing activities	–	(2)	–	–	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,006)	(163)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Dividends paid to parent in excess of retained earnings	–	–	(20)	20	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to noncontrolling interests	–	(85)	(10)	10	(85)
Changes in advances from affiliated companies	–	(21)	(215)	236	–
Contributions from parent	–	85	29	(114)	–
Other financing activities	–	1	(32)	5	(26)
Net cash (used) provided by financing activities	(42)	1,216	(116)	190	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(8)	–	(75)
Cash and cash equivalents at beginning of year	185	43	27	–	255
Cash and cash equivalents at end of year	$88	$73	$19	$–	$180

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2007 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$76	$489	$835	$(148)	$1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	625	(1)	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	–	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	791	–	1,452
Changes in advances to affiliated companies	(99)	(112)	(79)	290	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(7)	36	30
Net cash provided (used) by investing activities	231	(1,291)	(384)	(13)	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(483)	493	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	–	176
Net increase in short-term debt	25	–	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	–	739
Retirement of long-term debt	–	(124)	(200)	–	(324)
Cash distributions to noncontrolling interests	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	129	(280)	–
Contributions from parent	–	10	44	(54)	–
Other financing activities	–	49	14	2	65
Net cash (used) provided by financing activities	(275)	805	(496)	161	195
Net increase (decrease) in cash and cash equivalents	32	3	(45)	–	(10)
Cash and cash equivalents at beginning of year	153	40	72	–	265
Cash and cash equivalents at end of year	$185	$43	$27	$–	$255

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

(in millions except per share data)	First	Second	Third	Fourth
2009				
Operating revenues	**$2,442**	**$2,312**	**$2,824**	**$2,307**
Operating income	**393**	**379**	**676**	**324**
Income from continuing operations	**183**	**175**	**350**	**132**
Net income	**183**	**174**	**248**	**156**
Net income attributable to controlling interests	**182**	**174**	**247**	**154**
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	**0.66**	**0.62**	**1.24**	**0.46**
Net income attributable to controlling interests	**0.66**	**0.62**	**0.88**	**0.55**
Dividends declared per common share	**0.620**	**0.620**	**0.620**	**0.620**
Market price per share – High	**40.85**	**38.20**	**40.05**	**42.20**
– Low	**31.35**	**33.50**	**35.97**	**36.67**
2008[(a)]				
Operating revenues	$2,066	$2,244	$2,696	$2,161
Operating income	365	406	591	321
Income from continuing operations	153	200	309	116
Net income	214	205	310	107
Net income attributable to controlling interests	209	205	309	107
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.57	0.76	1.18	0.44
Net income attributable to controlling interests	0.80	0.78	1.18	0.41
Dividends declared per common share	0.615	0.615	0.615	0.620
Market price per share – High	49.16	43.58	45.52	45.60
– Low	40.54	41.00	40.11	32.60

(a) Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. Typically, weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our overall operating results may fluctuate substantially on a seasonal basis. During the fourth quarter of 2009, we recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $16 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to previously issued or current period financial statements.

Years ended December 31 *(in millions except per share data)*	**2009**	2008[a]	2007[a]	2006[a]	2005[a]
Operating results					
Operating revenues	**$9,885**	$9,167	$9,153	$8,724	$7,948
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**840**	778	702	567	527
Net income	**761**	836	496	620	668
Net income attributable to controlling interests	**757**	830	504	571	697
Per share data[b]					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$2.99**	$2.95	$2.70	$2.19	$2.10
Net income attributable to controlling interests	**2.71**	3.17	1.96	2.27	2.80
Assets	**$31,236**	$29,873	$26,338	$25,832	$27,083
Capitalization and debt					
Common stock equity	**$9,449**	$8,687	$8,395	$8,259	$8,011
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Noncontrolling interest	**6**	6	84	10	36
Long-term debt, net[c]	**12,051**	10,659	8,737	8,835	10,446
Current portion of long-term debt	**406**	–	877	324	513
Short-term debt	**140**	1,050	201	–	175
Capital lease obligations	**231**	239	247	72	18
Total capitalization and debt	**$22,376**	$20,734	$18,634	$17,593	$19,292
Other financial data					
Return on average common stock equity (percent)	**8.13**	9.59	5.97	7.05	8.92
Ratio of earnings to fixed charges	**2.66**	2.66	2.62	2.35	2.33
Number of common shareholders of record	**53,922**	55,919	58,991	64,899	67,638
Book value per common share	**$33.53**	$32.97	$32.41	$32.53	$32.16
Dividends declared per common share	**$2.48**	$2.47	$2.45	$2.43	$2.38
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**40,420**	46,771	51,163	48,770	52,306
Nuclear	**29,412**	30,565	30,336	30,602	30,120
Combustion turbines/combined cycle	**21,254**	15,557	13,319	11,857	11,349
Hydro	**651**	429	415	594	749
Purchased	**11,996**	14,956	14,994	14,664	14,566
Total energy supply (Company share)	**103,733**	108,278	110,227	106,487	109,090
Joint-owner share[d]	**5,500**	5,780	5,351	5,224	5,388
Total system energy supply	**109,233**	114,058	115,578	111,711	114,478

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

[b] Balances have been restated for the adoption of new accounting guidance, which redefined which securities and non-vested share-based compensation awards are considered to participate in our current earnings (See Note 2).

[c] Includes long-term debt to affiliated trust of $272 million at December 31, 2009 and 2008, $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005 (See Note 23).

[d] Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned.

Progress Energy's management uses Ongoing Earnings per share to evaluate the operations of the company and to establish goals for management and employees. 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 we believe are not representative of our fundamental core earnings. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies.

Reconciling adjustments from Ongoing Earnings to GAAP earnings for the years ended December 31 were as follows:

	2009	2008[a]	2007[a]
Ongoing Earnings per share	**$3.03**	$2.96	$2.71
CVO mark-to-market	**0.07**	–	(0.01)
Impairment	**(0.01)**	–	–
Plant retirement charge	**(0.06)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits	**(0.04)**	–	–
Valuation allowance and related net operating loss carry forward	**–**	(0.01)	–
Discontinued operations	**(0.28)**	0.22	(0.74)
Reported GAAP earnings per share	**$2.71**	$3.17	$1.96
Shares outstanding (millions)	**279**	262	257

[a] Previously reported 2008 and 2007 earnings per share have been restated to reflect the adoption of new accounting guidance that changed the calculation of the number of average common shares outstanding.

CVO Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, Progress Energy issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVO liability is valued at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. Progress Energy is unable to predict the changes in the fair value of the CVOs, and management does not consider this adjustment to be representative of the company's fundamental core earnings.

Impairment

The company has recorded impairments of certain investments of its Affordable Housing portfolio. Management believes this adjustment is not representative of the company's fundamental core earnings.

Plant Retirement Charges

The company recognized charges for the impact of PEC's decision to retire certain coal-fired generating units, with resulting reduced emissions for compliance with the Clean Smokestacks Act's 2013 emission targets. Since the coal-fired generating units will be retired prior to the end of their estimated useful lives, management does not consider these charges to be representative of the company's fundamental core earnings.

Cumulative Prior Period Adjustment Related to Certain Employee Life Insurance Benefits

In the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. Management believes this adjustment is not representative of the company's fundamental core earnings. The prior period adjustment was not material to previously issued or current period financial statements.

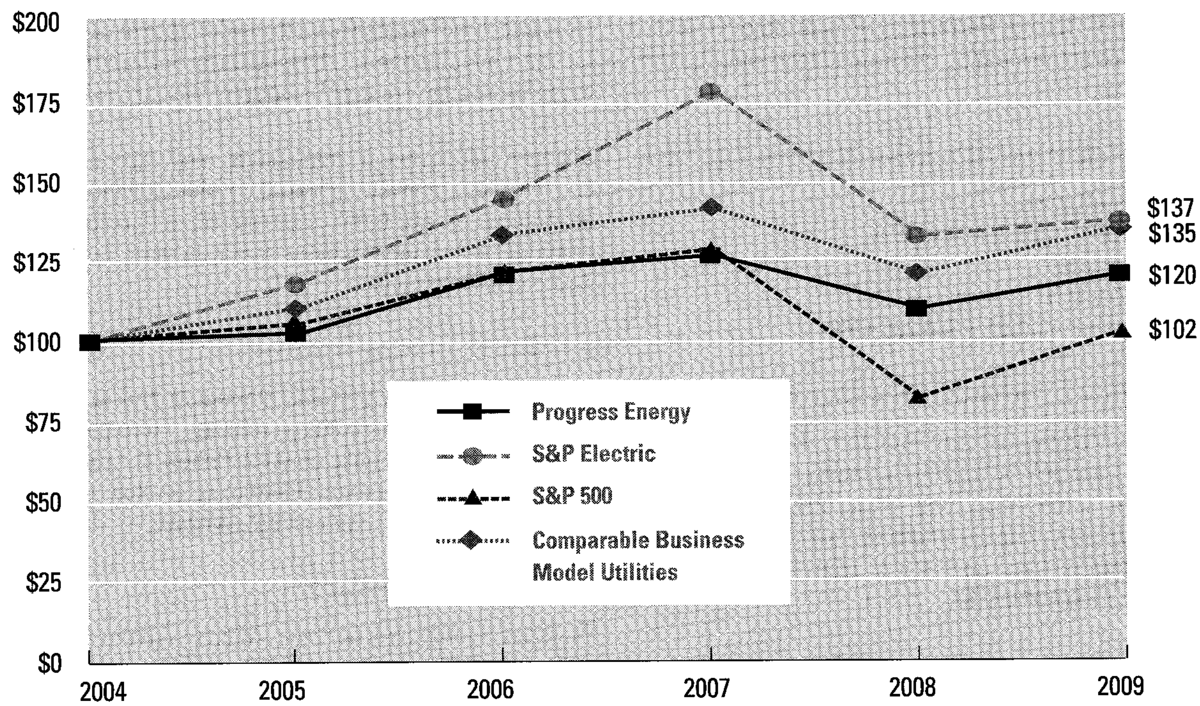
Valuation Allowance and Related Net Operating Loss Carry Forward

Progress Energy previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures Inc.'s nonregulated generation facilities and energy marketing and trading operations. In 2008, the company recorded an additional deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. The company also evaluated the total state net operating loss carry forward and partially impaired it by recording a valuation allowance, which more than offset the change in estimate. Management does not believe this net valuation allowance is representative of the company's fundamental core earnings.

Discontinued Operations

The company has reduced its business risk by exiting nonregulated businesses to focus on the core operations of the Utilities. Due to disposition of these assets, management does not view this activity as representative of the company's fundamental core earnings.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN* AMONG PROGRESS ENERGY, INC., S&P 500 STOCK INDEX, S&P ELECTRIC INDEX AND COMPARABLE BUSINESS MODEL UTILITIES



Measurement Period (Fiscal Year Covered)	2004	2005	2006	2007	2008	2009
Progress Energy, Inc.	$100	$102	$121	$126	$109	$120
S&P 500 Index	100	105	121	128	81	102
Comparable Business Model Utilities	100	110	133	141	120	135
S&P Electric Index	100	118	145	178	132	137

*$100 invested on 12/31/2004 in Stock or Index. Including reinvestment of dividends. Fiscal year ended December 31.

Over the past decade, as deregulation has occurred in several geographic areas of the United States, the investor community has separated the utility industry into a number of subsectors. The two main themes of separation are 1) the aspect of the value chain in which the company participates: generation, transmission and/or delivery, and 2) the proportion of its business governed by rate-of-return regulation as opposed to competitive markets. Thus, the industry now has subsectors identified frequently as competitive merchant, regulated delivery, regulated integrated, and unregulated integrated (typically state-regulated delivery and unregulated generation). Each of these subsectors typically differs in financial valuation characteristics and risk.

Progress Energy generally is identified as being in the regulated integrated subsector. This means Progress Energy and its peer companies are primarily rate-of-return regulated, operate in the full range of the value chain, and typically have requirements to serve all customers under state utility regulations. The companies similar to us from a business model perspective that are generally categorized in our subsector are American Electric Power, DPL, Duke Energy, Consolidated Edison, Great Plains Energy, Alliant Energy, NV Energy, PG&E, Pinnacle West, Portland General Electric, SCANA, Southern Company, Wisconsin Energy, Westar Energy and Xcel Energy.

It should be noted that, although the business models of several of these companies may not have been comparable to ours five years ago, their business models and ours are now similar due to industry evolution. The Company is providing this alternative market capitalization weighted index to show an additional comparison of Progress Energy's total return performance.

Notice of Annual Meeting

Progress Energy's 2010 annual meeting of shareholders will be held May 12, 2010, at 10 a.m. at the Progress Energy Center for the Performing Arts in Raleigh, N.C. A formal notice of the meeting will be mailed to shareholders in late March.

Transfer Agent and Registrar Mailing Address

Progress Energy, Inc.
c/o Computershare Trust Company
250 Royall Street
Canton, MA 02021
Toll-free phone number: **1.866.290.4388**

Shareholder Information and Inquiries

Obtain information on your account 24 hours a day, seven days a week by calling our stock transfer agent's shareholder information line. This automated system features Progress Energy's common stock closing price, dividend information and stock transfer information. Call toll-free **1.866.290.4388**.

Other questions concerning stock ownership may be directed to Progress Energy's Shareholder Relations by calling **919.546.3014** or by writing to the following address:

Progress Energy, Inc.
Shareholder Relations
410 S. Wilmington Street
Raleigh, NC 27601-1849

Stock Listings

Progress Energy's common stock is listed and traded under the symbol PGN on the New York Stock Exchange (NYSE) in addition to regional stock exchanges across the United States.

Shareholder Programs

Progress Energy offers the Progress Energy Investor Plus Plan, a direct stock-purchase and dividend-reinvestment plan, and direct deposit of cash dividends to bank accounts for the convenience of shareholders. For information on these programs, contact Computershare or the company.

Dividend-reinvestment statements and tax documents can be electronically delivered to shareholders. To take advantage of electronic delivery of documents, go to **computershare.com/investor**, log in to your account and select eDelivery options.

Securities Analyst Inquiries

Securities analysts, portfolio managers and representatives of financial institutions seeking information about Progress Energy should contact Robert F. Drennan, Jr., vice president, Investor Relations, at the corporate headquarters address or call **919.546.7474**.

Additional Information

Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders free of charge through the Investors section of our Web site at **www.progress-energy.com** or upon written request to the company's treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information and is available for delivery to shareholders in connection with our 2010 annual meeting of shareholders. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

Cautionary Statement

This report contains forward-looking statements relating to Progress Energy's business. Our business is subject to numerous risks and uncertainties, which could cause actual results to differ materially from those expressed or implied by these forward-looking statements. We refer you to our Annual Report on Form 10-K for a discussion of such risks and uncertainties.

NOTICE OF ANNUAL MEETING AND PROXY STATEMENT

Progress Energy

Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, NC 27601-1849

March 31, 2010

Dear Shareholder:

I am pleased to invite you to attend the 2010 Annual Meeting of the Shareholders of Progress Energy, Inc. The meeting will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina.

As described in the accompanying Notice of Annual Meeting of Shareholders and Proxy Statement, the matters scheduled to be acted upon at the meeting for Progress Energy, Inc. are the election of directors, the ratification of the selection of the independent registered public accounting firm for Progress Energy, Inc., and a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards.

We are pleased to take advantage of the Securities and Exchange Commission rules that permit companies to electronically deliver proxy materials to their shareholders. This process allows us to provide our shareholders with the information they need while lowering printing and mailing costs and more efficiently complying with our obligations under the securities laws. On or about March 31, 2010, we mailed to our registered and beneficial shareholders a Notice containing instructions on how to access our combined Proxy Statement and Annual Report and vote online.

Regardless of the size of your holdings, it is important that your shares be represented at the meeting. IN ADDITION TO VOTING IN PERSON AT THE MEETING, SHAREHOLDERS OF RECORD MAY VOTE VIA A TOLL-FREE TELEPHONE NUMBER OR OVER THE INTERNET. SHAREHOLDERS WHO RECEIVED A PAPER COPY OF THE PROXY STATEMENT AND THE ANNUAL REPORT MAY ALSO VOTE BY COMPLETING, SIGNING AND MAILING THE ACCOMPANYING PROXY CARD IN THE RETURN ENVELOPE PROVIDED AS SOON AS POSSIBLE. IF YOUR SHARES ARE HELD IN THE NAME OF A BANK, BROKER OR OTHER HOLDER OF RECORD, CHECK YOUR PROXY CARD TO SEE WHICH OPTIONS ARE AVAILABLE TO YOU. Voting by any of these methods will ensure that your vote is counted at the Annual Meeting if you do not attend in person.

I am delighted that you have chosen to invest in Progress Energy, Inc., and look forward to seeing you at the meeting. On behalf of the management and directors of Progress Energy, Inc., thank you for your continued support and confidence in 2010.

Sincerely,

William D. Johnson

William D. Johnson
Chairman of the Board, President and
Chief Executive Officer

VOTING YOUR PROXY IS IMPORTANT

Your vote is important. To ensure your representation at the Annual Meeting, please vote your shares as promptly as possible. In addition to voting in person, shareholders of record may **VOTE VIA A TOLL-FREE TELEPHONE NUMBER OR OVER THE INTERNET**, as instructed in the materials.

If you received this Proxy Statement by mail, please promptly **SIGN, DATE and RETURN** the enclosed proxy card or **VOTE BY TELEPHONE** in accordance with the instructions on the enclosed proxy card so that as many shares as possible will be represented at the Annual Meeting. A self-addressed envelope, which requires no postage if mailed in the United States, is enclosed for your convenience.

PROGRESS ENERGY, INC.
410 S. Wilmington Street
Raleigh, North Carolina 27601-1849

NOTICE OF THE ANNUAL MEETING OF SHAREHOLDERS TO BE HELD ON

MAY 12, 2010

The Annual Meeting of the Shareholders of Progress Energy, Inc. (the "Company") will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. The meeting will be held in order to:

(1) Elect fourteen (14) directors of the Company, each to serve a one-year term. The Board of Directors recommends a vote **FOR** each of the nominees for director.

(2) Ratify the selection of Deloitte & Touche LLP as the independent registered public accounting firm for the Company. The Board of Directors recommends a vote **FOR** the ratification of the selection of Deloitte & Touche LLP as the Company's independent registered public accounting firm.

(3) Vote on a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards. The Board of Directors recommends a vote **AGAINST** the shareholder proposal.

(4) Transact any other business as may properly be brought before the meeting.

All holders of the Company's Common Stock of record at the close of business on March 5, 2010, are entitled to attend the meeting and to vote. The stock transfer books will remain open.

By order of the Board of Directors

JOHN R. MCARTHUR
Executive Vice President
and Corporate Secretary

Raleigh, North Carolina
March 31, 2010

PROXY STATEMENT

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PROGRESS ENERGY, INC.

410 S. Wilmington Street
Raleigh, North Carolina 27601-1849

PROXY STATEMENT
GENERAL

This Proxy Statement is furnished in connection with the solicitation by the Board of Directors (at times referred to as the "Board") of proxies to be used at the Annual Meeting of Shareholders. That meeting will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. (For directions to the meeting location, please see the map included at the end of this Proxy Statement.) Throughout this Proxy Statement, Progress Energy, Inc. is at times referred to as "Progress Energy," "we," "our" or "us." This Proxy Statement and form of proxy were first sent to shareholders on or about March 31, 2010.

An audio Webcast of the Annual Meeting of Shareholders will be available online in Windows Media Player format at *www.progress-energy.com/investor*. The Webcast will be archived on the site for three months following the date of the meeting.

Copies of our Annual Report on Form 10-K for the year ended December 31, 2009, including financial statements and schedules, are available upon written request, without charge, to the persons whose proxies are solicited. Any exhibit to the Form 10-K is also available upon written request at a reasonable charge for copying and mailing. Written requests should be made to Mr. Thomas R. Sullivan, Treasurer, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551. Our Form 10-K is also available through the Securities and Exchange Commission's (the "SEC") Web site at *www.sec.gov* or through our Web site at *www.progress-energy.com/investor*. The contents of these Web sites are not, and shall not be deemed to be, a part of this Proxy Statement or proxy solicitation materials.

In accordance with the "notice and access" rule adopted by the SEC, we are making our proxy materials available to our shareholders on the Internet, and we are mailing to our registered and beneficial holders a "Notice of Internet Availability of Proxy Materials" containing instructions on how to access our proxy materials and how to vote on the Internet and by telephone. If you received a "Notice of Internet Availability of Proxy Materials" and would like to receive a printed copy of our proxy materials, free of charge, you should follow the instructions for requesting such materials below.

We have adopted a procedure approved by the SEC called "householding." Under this procedure, shareholders of record who have the same address and last name and do not participate in the electronic delivery of proxy materials will receive only one copy of our Proxy Statement and Annual Report, unless one or more of the shareholders at that address notifies us that they wish to continue receiving individual copies. We believe this procedure provides greater convenience to our shareholders and saves money by reducing our printing and mailing costs and fees.

If you prefer to receive a separate copy of our combined Proxy Statement and Annual Report, please write to Shareholder Relations, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551 or telephone our Shareholder Relations Section at 919-546-3014, and we will promptly send you a separate copy. If you are currently receiving multiple copies of the Proxy Statement and Annual Report at your address and would prefer that a single copy of each be delivered there, you may contact us at the address or telephone number provided in this paragraph.

PROXIES

The accompanying proxy is solicited by our Board of Directors, and we will bear the entire cost of solicitation. We expect to solicit proxies primarily by telephone, mail, e-mail or other electronic media or personally by our and our subsidiaries' officers and employees, who will not be specially compensated for such services. In addition, the Company will engage Morrow & Co., LLC, if necessary, to assist in the solicitation of proxies on behalf of the Board. It is anticipated that the cost of the solicitation service to the Company will be approximately $35,000 plus out-of-pocket expenses.

You may vote shares either in person or by duly authorized proxy. In addition, you may vote your shares by telephone or via the Internet by following the instructions provided on the enclosed proxy card. Please be aware that if you vote via the Internet, you may incur costs such as telecommunication and Internet access charges for which you will be responsible. The Internet and telephone voting facilities for shareholders of record will close at 12:01 a.m. E.D.T. on the morning of the meeting. Any shareholder who has executed a proxy and attends the meeting may elect to vote in person rather than by proxy. You may revoke any proxy given by you in response to this solicitation at any time before the proxy is exercised by (i) delivering a written notice of revocation to our Corporate Secretary, (ii) timely filing, with our Corporate Secretary, a subsequently dated, properly executed proxy, or (iii) attending the Annual Meeting and electing to vote in person. Your attendance at the Annual Meeting, by itself, will not constitute a revocation of a proxy. If you vote by telephone or via the Internet, you may also revoke your vote by any of the three methods noted above, or you may change your vote by voting again by telephone or via the Internet. If you decide to vote by completing and mailing the enclosed proxy card, you should retain a copy of certain identifying information found on the proxy card in the event that you decide later to change or revoke your proxy by accessing the Internet. You should address any written notices of proxy revocation to: Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551, Attention: Corporate Secretary.

All shares represented by effective proxies received by the Company at or before the Annual Meeting, and not revoked before they are exercised, will be voted in the manner specified therein. Executed proxies that do not contain voting instructions will be voted **"FOR"** the election of all directors as set forth in this Proxy Statement; **"FOR"** the ratification of the selection of Deloitte & Touche LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2010, as set forth in this Proxy Statement; and **"AGAINST"** the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards as set forth in this Proxy Statement. Proxies will be voted at the discretion of the named proxies on any other business properly brought before the meeting.

If you are a participant in our 401(k) Savings & Stock Ownership Plan, shares allocated to your Plan account will be voted by the Trustee only if you execute and return your proxy, or vote by telephone or via the Internet. Plan participants must provide voting instructions on or before 11:59 p.m. E.D.T. on May 9, 2010. Company stock remaining in the ESOP Stock Suspense Account that has not been allocated to employee accounts shall be voted by the Trustee in the same proportion as shares voted by participants in the 401(k) Plan.

If you are a participant in the Savings Plan for Employees of Florida Progress Corporation (the "FPC Savings Plan"), shares allocated to your Plan account will be voted by the Trustee when you execute and return your proxy, or vote by telephone or via the Internet. If no direction is given, your shares will be voted in proportion with the shares held in the FPC Savings Plan and in the best interest of the FPC Savings Plan.

Special Note for Shares Held in "Street Name"

If your shares are held by a brokerage firm, bank or other nominee (i.e., in "street name"), you will receive directions from your nominee that you must follow in order to have your shares voted. "Street name" shareholders who wish to vote in person at the meeting will need to obtain a special proxy form from the brokerage firm, bank or other nominee that holds their shares of record. You should contact your brokerage firm, bank or other nominee for details regarding how you may obtain this special proxy form.

If your shares are held in "street name" and you do not give instructions as to how you want your shares voted (a "nonvote"), the brokerage firm, bank or other nominee who holds Progress Energy shares on your behalf may vote the shares at its discretion with regard to "routine" matters. However, such brokerage firm, bank or other nominee is not required to vote the shares of Common Stock, and therefore these unvoted shares would be counted as "broker nonvotes."

With respect to "routine" matters, such as the ratification of the selection of the independent registered public accounting firm, a brokerage firm, bank or other nominee has authority (but is not required) under the rules governing self-regulatory organizations (the "SRO rules"), including the New York Stock Exchange ("NYSE"), to vote its clients' shares if the clients do not provide instructions. When a brokerage firm, bank or other nominee votes its clients' Common Stock shares on routine matters without receiving voting instructions, these shares are counted both for establishing a quorum to conduct business at the meeting and in determining the number of shares voted **"FOR"** or **"AGAINST"** such routine matters. The NYSE recently amended its rules to make the election of directors a "nonroutine" matter.

With respect to "nonroutine" matters, including the election of directors and shareholder proposals, a brokerage firm, bank or other nominee is not permitted under the SRO rules to vote its clients' shares if the clients do not specifically instruct their brokerage firm, bank or other nominee on how to vote their shares. The brokerage firm, bank or other nominee will so note on the vote card, and this constitutes a "broker nonvote." "Broker nonvotes" will be counted for purposes of establishing a quorum to conduct business at the meeting but not for determining the number of shares voted **"FOR," "AGAINST"** or **"ABSTAINING"** from such nonroutine matters. At the 2010 Annual Meeting of Shareholders, two nonroutine matters, the election of 14 directors of the Company with terms expiring in 2011 and a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards, will be presented for a vote.

Accordingly, if you do not vote your proxy, your brokerage firm, bank or other nominee may either: (i) vote your shares on routine matters and cast a "broker nonvote" on nonroutine matters, or (ii) leave your shares unvoted altogether. Therefore, we encourage you to provide instructions to your brokerage firm, bank or other nominee by voting your proxy. This action ensures that your shares and voting preferences will be fully represented at the meeting.

VOTING SECURITIES

Our directors have fixed March 5, 2010, as the record date for shareholders entitled to vote at the Annual Meeting. Only holders of our Common Stock of record at the close of business on that date are entitled to notice of and to vote at the Annual Meeting. Each share is entitled to one vote. As of March 5, 2010, there were outstanding 284,645,924 shares of Common Stock.

Consistent with state law and our By-Laws, the presence, in person or by proxy, of holders of at least a majority of the total number of Common Stock shares entitled to vote is necessary to constitute a quorum for the transaction of business at the Annual Meeting. Once a share of Common Stock is represented for any purpose at a meeting, it is deemed present for quorum purposes for the remainder of the meeting and any adjournment thereof, unless a new record date is or must be set in connection with any adjournment. Common Stock shares held of record by shareholders or their nominees who do not vote by proxy or attend the Annual Meeting in person will not be considered present or represented at the Annual Meeting and will not be counted in determining the presence of a quorum. Proxies that withhold authority or reflect abstentions or "broker nonvotes" will be counted for purposes of determining whether a quorum is present.

Pursuant to the provisions of our Articles of Incorporation, as amended effective May 10, 2006, a candidate for director will be elected upon receipt of at least a majority of the votes cast by the holders of Common Stock entitled to vote. Accordingly, assuming a quorum is present, each director shall be elected by a vote of the majority of the votes cast with respect to that director. A majority of the votes cast means that the number of shares voted **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director. Shares voting **"ABSTAIN"** and shares held in "street name" that are not voted in the election of directors will not be included in determining the number of votes cast.

Approval of the proposal to ratify the selection of our independent registered public accounting firm, and other matters properly brought before the Annual Meeting, if any, generally will require the affirmative vote of a majority of votes actually cast by holders of Common Stock entitled to vote. Assuming a quorum is present, the number of **"FOR"** votes cast at the meeting for this proposal must exceed the number of **"AGAINST"** votes cast at the meeting in order for this proposal to be approved. Abstentions from voting and "broker nonvotes" will not count as votes cast and will not have the effect of a "negative" vote with respect to any such matters.

Approval of the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards will require the affirmative vote of a majority of the shares cast on the proposal provided that the total votes cast on the proposal represents over 50 percent of the shares entitled to vote on the proposal. Abstentions will not have the effect of "negative" votes with respect to the proposal. Shares held in "street name" that are not voted with respect to the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards will not be included in determining the number of votes cast.

We will announce preliminary voting results at the Annual Meeting. We will publish the final results in a current report on Form 8-K within four (4) business days of the Annual Meeting. A copy of this Form 8-K may be obtained without charge by any of the means outlined above for obtaining a copy of our Annual Report on Form 10-K.

PROPOSAL 1—ELECTION OF DIRECTORS

The Company's amended By-Laws provide that the number of directors of the Company shall be between eleven (11) and fifteen (15). The amended By-Laws also provide for annual elections of each director. Directors will serve one-year terms upon election at the 2010 Annual Meeting of Shareholders.

Our Articles of Incorporation require that a candidate in an uncontested election for director receive a majority of the votes cast in order to be elected as a director (i.e., the number of votes cast **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director). In a contested election (i.e., a situation in which the number of nominees exceeds the number of directors to be elected), the standard for election of directors will be a plurality of the votes cast. Under North Carolina law, a director continues to serve in office until his or her successor is elected or until there is a decrease in the number of directors, even if the director is a candidate for re-election and does not receive the required vote, referred to as a "holdover director." To address the potential for such a "holdover director," our Board of Directors approved a provision in our Corporate Governance Guidelines. That provision states that if an incumbent director is nominated, but not re-elected by a majority vote, the director shall tender his or her resignation to the Board. The Corporate Governance Committee (the "Governance Committee") would then make a recommendation to the Board whether to accept or reject the resignation. The Board will act on the Governance Committee's recommendation and publicly disclose its decision and the rationale regarding it within 90 days after receipt of the tendered resignation. Any director who tenders his or her resignation pursuant to this provision shall not participate in the Governance Committee's recommendation or Board of Directors' action regarding the acceptance of the resignation offer. However, if all members of the Governance Committee do not receive a vote sufficient for re-election, then the independent directors who did not fail to receive a sufficient vote shall appoint a committee amongst themselves to consider the resignation offers and recommend to the Board of Directors whether to accept them. If the only directors who did not fail to receive a sufficient vote for re-election constitute three or fewer directors, all directors may participate in the action regarding whether to accept the resignation offers.

Based on the report of the Governance Committee (see page 15), the Board of Directors nominates the following 14 nominees to serve as directors with terms expiring in 2011 and until their respective successors are elected and qualified: John D. Baker II, James E. Bostic, Jr., Harris E. DeLoach, Jr., James B. Hyler, Jr., William D. Johnson, Robert W. Jones, W. Steven Jones, Melquiades R. "Mel" Martinez, E. Marie McKee, John H. Mullin, III, Charles W. Pryor, Jr., Carlos A. Saladrigas, Theresa M. Stone, and Alfred C. Tollison, Jr.

There are no family relationships between any of the directors, any executive officers or nominees for director of the Company or its subsidiaries, and there is no arrangement or understanding between any director or director nominee and any other person pursuant to which the director or director nominee was selected.

The election of directors will be determined by a majority of the votes cast at the Annual Meeting at which a quorum is present. This means that the number of votes cast **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director in order for the director to be elected. Abstentions and broker nonvotes, if any, are not treated as votes cast and, therefore, will have no effect on the proposal to elect directors. Shareholders do not have cumulative voting rights in connection with the election of directors.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where specifications are not made, the shares represented by the accompanying proxy will be voted **"FOR"** the election of each of the 14 nominees. Votes (other than abstentions) will be cast pursuant to the accompanying proxy for the election of the nominees listed above unless, by reason of death or other unexpected occurrence, one or more of such nominees shall not be available for election, in which event it is intended that such votes will be cast for such substitute nominee or nominees as may be determined by the persons named in such proxy. The Board of Directors has no reason to believe that any of the nominees listed above will not be available for election as a director.

The Board of Directors, acting through the Governance Committee, is responsible for assembling for shareholder consideration a group of nominees that, taken together, have the experience, qualifications, attributes and skills appropriate for functioning effectively as a board. The Governance Committee regularly reviews the composition of the Board in light of the Company's changing requirements and its assessment of the Board's performance. A discussion of the characteristics the Governance Committee looks for in evaluating director candidates appears in the "Governance Committee Process for Identifying and Evaluating Director Candidates" section on page 18 of this Proxy Statement.

The names of the 14 nominees for election to the Board of Directors, along with their ages, principal occupations or employment for the past five years, directorships of public companies held during the past five years, and disclosures regarding the specific experience, qualifications, attributes or skills that led the Board to conclude that such individual should serve on the Board, are set forth below. Messrs. John D. Baker II and Melquiades R. "Mel" Martinez, who were elected by the Board on September 17, 2009 and March 1, 2010, respectively, are directors standing for election to the Board by our shareholders for the first time. Mr. Baker was recommended to the Governance Committee by one of our non-management directors, and Mr. Martinez was recommended to the Governance Committee by William D. Johnson, who is our Chairman of the Board, President and Chief Executive Officer. (Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC") and Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), which are noted below, are wholly owned subsidiaries of the Company.) Information concerning the number of shares of our Common Stock beneficially owned, directly or indirectly, by all current directors appears on page 10 of this Proxy Statement.

The Board of Directors recommends a vote **"FOR"** each nominee for director.

Nominees for Election

JOHN D. BAKER II, age 61, is President and Chief Executive Officer of Patriot Transportation Holding, Inc., which is engaged in the transportation and real estate businesses. He has served in these positions since November 2007. Mr. Baker was President and Chief Executive Officer of Florida Rock Industries, Inc., a producer of cement, aggregates, concrete and concrete products from 1997 to 2007. As a lawyer and business executive with more than 35 years of experience in the construction materials and trucking industries, Mr. Baker brings business insight and expertise that will be valuable to the Company as it navigates a complex and changing business environment. Mr. Baker has served as a director of the Company since September 17, 2009 and is a member of the Board's Finance Committee and the Organization and Compensation Committee.

Other public directorships in past five years:
Patriot Transportation Holding, Inc. (1986 to present)
Wells Fargo & Company (January 2009 to present)
Vulcan Materials Co. (November 2007 until February 2009)
Wachovia Bank, N.A. (2001 to December 2008)
Florida Rock Industries, Inc. (1979 until November 2007)
Hughes Supply, Inc. (1994 until 2006)

JAMES E. BOSTIC, JR., age 62, has been Managing Director of HEP & Associates, a business consulting firm, and a partner of Coleman Lew & Associates, an executive search consulting firm, since 2006. He retired as Executive Vice President of Georgia-Pacific Corporation, a manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals, in 2006. During his 20 years at Georgia-Pacific, Mr. Bostic served in various senior positions, including a stint as senior vice president—Environmental, Government Affairs and Communications. Over the years, Mr. Bostic's business background and his expertise on environmental and regulatory issues have been significant assets to the Company. That expertise will be particularly helpful as we continue to address new laws and regulations regarding global climate change and other environmental issues. Additionally, due to his years of service on the Board, Mr. Bostic has developed a keen understanding of how the Company operates, the key issues it faces, and its strategy for addressing those issues as it carries out its responsibilities to its shareholders and other stakeholders. He has served as a director of the Company since 2002. Mr. Bostic is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

HARRIS E. DELOACH, JR., age 65, is Chairman, President and Chief Executive Officer of Sonoco Products Company, a manufacturer of paperboard and paper and plastic packaging products, since April 2005. He served as President and Chief Executive Officer of Sonoco Products from July 2000 to April 2005. Mr. DeLoach joined Sonoco Products in 1986 and has served in various management positions during his tenure there. Prior to joining Sonoco, Mr. DeLoach was in private law practice and served as an outside counsel to Sonoco for 15 years. Mr. DeLoach's legal background and years of experience leading a global packaging company will be valuable to the Company as it confronts a challenging economy and changing business environment. He has served as a director of the Company since 2006. Mr. DeLoach is Chair of the Board's Operations and Nuclear Oversight Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Organization and Compensation Committee.

Other public directorships in past five years:
Sonoco Products Company (1998 to present)
Goodrich Corporation (2001 to present)

JAMES B. HYLER, JR., age 62, retired as Vice Chairman and Chief Operating Officer of First Citizens Bank in 2008. He served in these positions from 1994 until 2008. Mr. Hyler was Chief Financial Officer of First Citizens Bank from 1980 to 1988, and served as President of First Citizens Bank from 1988 to 1994. Prior to joining First Citizens Bank, Mr. Hyler was an auditor with Ernst & Young for 10 years. Mr. Hyler has more than 37 years of experience in the financial services industry. Mr. Hyler's experience and accounting background have provided him with an understanding of the accounting principles used by the Company to prepare its financial statements and the ability to analyze such statements. His knowledge and experience in financial services and corporate finance will be valuable to the Company as our utilities continue to move forward with the expansion projects necessary to meet our customers' future energy needs reliably and affordably. Mr. Hyler has served as a director of the Company since 2008 and is a member of the Board's Finance Committee and the Organization and Compensation Committee.

Other public directorships in past five years:
First Citizens BancShares (August 1988 until January 2008)

WILLIAM D. JOHNSON, age 56, is Chairman, President and Chief Executive Officer of Progress Energy, since October 2007. Mr. Johnson previously served as President and Chief Operating Officer of Progress Energy from January 2005 to October 2007. In that role, Mr. Johnson oversaw the generation and delivery of electricity by PEC and PEF. Mr. Johnson has been with Progress Energy (formerly CP&L) in a number of roles since 1992, including Group President for Energy Delivery, President and Chief Executive Officer for Progress Energy Service Company, LLC and General Counsel and Secretary for Progress Energy. Before joining Progress Energy, Mr. Johnson was a partner with the Raleigh, N.C. law office of Hunton & Williams LLP, where he specialized in the representation of utilities. Mr. Johnson has served in a variety of senior management positions during his tenure with the Company. His background as a lawyer representing utilities, and his years of hands-on experience at the Company, provide him a unique perspective and a keen understanding of the Company and our industry. Mr. Johnson's breadth of knowledge and experience in addressing key operational, policy, legislative and strategic issues, and his proven leadership skills, will be significant assets to the Company as it implements its long-term strategy in the face of a challenging economy and a changing regulatory and legislative environment. He has served as a director of the Company since 2007.

ROBERT W. JONES, age 59, is the sole owner of Turtle Rock Group, LLC, founded in May 2009. From 1974 until May 2009, Mr. Jones held various management positions at Morgan Stanley, a global provider of financial services to companies, governments and investors. He served as a Senior Advisor from 2006 until May of 2009, and as Managing Director and Vice Chairman from 1997 until 2006. While at Morgan Stanley, Mr. Jones specialized in the utility industry for many years before being named Vice Chairman. Turtle Rock Group, LLC is a financial advisory consulting firm whose sole current client is Morgan Stanley. During his career, Mr. Jones has participated in many major international and domestic utility and project financing transactions, with a particular focus on strategic advisory and capital raising assignments. He has testified before numerous state public utility commissions and has been a frequent speaker on regulatory and corporate governance issues. Mr. Jones's expertise in financial services and his experience in the regulatory arena provide him with a unique perspective that will be beneficial to the Company as it undertakes the expansion projects necessary to implement its balanced solution to meeting its customers' future energy needs in a challenging economy and uncertain regulatory environment. He has served as a director of the Company since 2007. Mr. Jones is Chair of the Board's Finance Committee and a member of the Executive Committee, the Governance Committee and the Organization and Compensation Committee.

W. STEVEN JONES, age 58, is Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill, since 2008. He served as Dean of the Kenan-Flagler Business School from August 2003 until August 2008. Prior to joining the Kenan-Flagler Business School in 2003, Mr. Jones had a 30-year career in business. That career included serving as Chief Executive Officer and Managing Director of Suncorp-Metway Ltd., which provides banking, insurance and investing services in Brisbane, Queensland, Australia. He also worked for ANZ, one of Australia's four major banks, in various capacities for eight years. Mr. Jones has international experience in developing strategy, leading change and building organizational capability in a variety of industries. His expertise in the financial services arena will continue to be beneficial as the Company prepares to undertake the expansion projects necessary to satisfy its customers' future energy needs reliably and affordably. Mr. Jones has served as a director of the Company since 2005. He is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

Other public directorships in past five years:
Premiere Global Services, Inc. (2007 to present)
Bank of America (April 2005 to April 2008)

MELQUIADES R. "MEL" MARTINEZ, age 63, is currently a partner in the law firm of DLA Piper in its Orlando office. Mr. Martinez has had a distinguished career in both the public and private sectors, most recently as a United States Senator from Florida. While serving in the U.S. Senate from 2005 to 2009, he addressed multiple policy and legislative issues as a member of the following Senate committees: Armed Services; Banking, Housing & Urban Affairs; Foreign Relations; Energy and Natural Resources; Commerce; and Special Committee on Aging. Prior to his election, Mr. Martinez served as the Secretary of Housing and Urban Development from 2001 to 2004. His extensive legal, policy and legislative experience will be valuable to the Company as we address new laws and regulations in areas such as environmental compliance, renewable energy standards and energy policy. Prior to representing the State of Florida in the U.S. Senate, Mr. Martinez served as Mayor of Orange County Florida, and as a board member of the Orlando Utilities Commission. He also spent over 25 years in private legal practice, conducting numerous trials in state and federal courts throughout Florida. As a resident and public servant of the State of Florida, Mr. Martinez brings to our Board a unique perspective and first-hand knowledge that will be beneficial as we continue to address key regulatory issues in that State. Mr. Martinez's diversified experience and background will be significant assets to our Company's Board. He has served as a director of the Company since March 1, 2010 and is a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee.

E. MARIE MCKEE, age 59, is Senior Vice President of Corning Incorporated, a manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences, since 1996. She also serves as President of the Corning Museum of Glass. Ms. McKee has over 30 years of experience at Corning, where she has held a variety of positions with increasing levels of responsibility. She initially served in various human resources manager positions including Human Resources Director for Corning's Electronics Division, its Research & Development Division and its Centralized Engineering Division. While serving in these positions, Ms. McKee gained significant experience in designing and implementing human resources strategies, business processes and organizational change efforts. She then served in various management positions, including Division Vice President of Corporate Strategic Staffing, Vice President, Human Resources and Senior Vice President, Human Resources and Corporate Diversity Officer. Ms. McKee served as Chairman of Steuben Glass from 1998 until the company was sold in 2008. Ms. McKee has served as a director of the Company and its predecessors since 1999. During her tenure on the Board, Ms. McKee's business experience and perspective have proven valuable to the Company as it has addressed various operational and human resources issues, including executive compensation, succession planning and diversity. Ms. McKee's experience will continue to be beneficial to the Company as shareholders, regulators and legislators continue to focus on executive compensation and corporate governance issues. Ms. McKee is Chair of the Board's Organization and Compensation Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

JOHN H. MULLIN, III, age 68, is Chairman of Ridgeway Farm, LLC, a limited liability company engaged in farming and timber management, since 1989. He is a former Managing Director of Dillon, Read & Co., a former investment banking firm. Mr. Mullin was employed by Dillon Read for approximately 20 years. During that time, he worked with a diversified mix of clients and was involved in a variety of corporate assignments, including private and public offerings, and corporate restructurings. Since 1989, Mr. Mullin has managed the diversified businesses of Ridgeway Farm. He has served on the boards of a number of other major publicly traded companies, providing him with substantial experience in the areas of corporate strategy, oversight and governance. Mr. Mullin has utilized his broad and extensive business experiences to provide leadership to the Company's Board as Lead Director. He has served as a director of the Company and its predecessors since 1999. Mr. Mullin is Chair of the Board's Governance Committee and a member of the Executive Committee, the Finance Committee and the Organization and Compensation Committee.

Other public directorships in past five years:
Sonoco Products Company (2002 to present)
Hess Corporation (2007 to present)
Liberty Corporation (1989 to 2006)

CHARLES W. PRYOR, JR., age 65, is Chairman of Urenco Investments, Inc., a global provider of services and technology to the nuclear generation industry worldwide, since January 2007. He served as President and Chief Executive Officer of Urenco Investments, Inc. from 2004 to 2006. Mr. Pryor served as President and Chief Executive Officer of the Utilities Business Group of British Nuclear Fuels from 2002 to 2004. From 1997 to 2002, he served as President and Chief Executive Officer of Westinghouse Electric Co., a supplier of nuclear fuel, nuclear services and advanced nuclear plant designs to utilities operating nuclear power plants. Mr. Pryor's service as chief executive officer of a multi-billion dollar company provided him with experience that enables him to understand the financial statements and financial affairs of the Company. Mr. Pryor's knowledge and experience in engineering, power generation, nuclear fuel and the utility industry will help us in the years ahead as our Company pursues a balanced solution to meeting its customers' future energy needs. He has served as a director of the Company since 2007. Mr. Pryor is Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee.

Other public directorships in past five years:
DTE Energy Co. (1999 to present)

CARLOS A. SALADRIGAS, age 61, is Chairman and Chief Executive Officer of Regis HRG, which offers a full suite of outsourced human resources services to small and mid-sized businesses. He has served in these positions since July 2008. Mr. Saladrigas served as Chairman, from 2002 to 2007, and Vice Chairman, from 2007 to 2008, of Premier American Bank in Miami, Florida. In 2002, Mr. Saladrigas retired as Chief Executive Officer of ADP Total Source (previously the Vincam Group, Inc.), a Miami-based human resources outsourcing company that provides services to small and mid-sized businesses. Mr. Saladrigas has extensive expertise in both the human resources and financial services arenas. His accounting background provides him with an understanding of the principles used to prepare the Company's financial statements and enables him to effectively analyze those financial statements. Mr. Saladrigas is a resident of Florida and is familiar with the policy issues facing that State. His unique perspective and business acumen continue to be valuable assets to the Board. Mr. Saladrigas has served as a director of the Company since 2001 and is a member of the Board's Audit and Corporate Performance Committee and the Finance Committee.

Other public directorships in past five years:
Advance Auto Parts, Inc. (2003 to present)

THERESA M. STONE, age 65, has been Executive Vice President and Treasurer of the Massachusetts Institute of Technology Corporation ("M.I.T."), since February 2007. In her role as Executive Vice President and Treasurer, Ms. Stone is responsible for M.I.T.'s capital programs, facilities, human resources and information technology, and serves as M.I.T.'s Chief Financial Officer and Treasurer. Prior to serving in her current role, Ms. Stone served as Executive Vice President and Chief Financial Officer of Jefferson-Pilot Financial (now Lincoln Financial Group) from November 2001 to March 2006. Ms. Stone began her career as an investment banker, advising clients primarily in the financial services industry on financial and strategic matters and has held senior financial executive officer positions at various companies since that time. Ms. Stone's knowledge and expertise in finance make her uniquely qualified to understand and effectively analyze the Company's financial statements, and to assist the Company as it undertakes the expansion efforts necessary to implement its balanced solution to satisfying its customers' energy needs reliably and affordably. She has served as a director of the Company since 2005. Ms. Stone is Chair of the Board's Audit and Corporate Performance Committee and a member of the Executive Committee, the Governance Committee and the Finance Committee.

ALFRED C. TOLLISON, JR., age 67, retired as Chairman and Chief Executive Officer of the Institute of Nuclear Power Operations ("INPO"), a nuclear industry-sponsored nonprofit organization in March 2006. He was employed by INPO from 1987 until March 2006. During his tenure there, Mr. Tollison's responsibilities included industry and government relations, communications, information systems and administrative activities. He also served as the executive director of the National Academy for Nuclear Training. From 1970 until 1987, Mr. Tollison was employed by PEC, where he served in a variety of management positions, including plant general manager of the Brunswick Nuclear Plant and manager of nuclear training. Mr. Tollison's track record and expertise in promoting the safe and reliable operations of our nation's nuclear generating plants will continue to be a significant asset to our board as the Company moves forward with its balanced solution for meeting the future generation needs of its customers safely, reliably and affordably. He has served as a director of the Company since 2006. Mr. Tollison is Vice Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee. He also serves as the Nuclear Oversight Director.

PRINCIPAL SHAREHOLDERS

The table below sets forth the only shareholder we know to beneficially own more than 5 percent (5%) of the outstanding shares of our Common Stock as of December 31, 2009. We do not have any other class of voting securities.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
Common Stock	State Street Corporation One Lincoln Street Boston, MA 02111	25,939,712[1]	9.3

[1] Consists of shares of Common Stock held by State Street Corporation, acting in various fiduciary capacities. State Street Corporation has sole power to vote with respect to 0 shares, sole dispositive power with respect to 0 shares, shared power to vote with respect to 12,892,635 shares and shared power to dispose of 25,939,712 shares. State Street Corporation has disclaimed beneficial ownership of all shares of Common Stock. (Based solely on information contained in a Schedule 13G filed by State Street Corporation on February 12, 2010.)

MANAGEMENT OWNERSHIP OF COMMON STOCK

The following table describes the beneficial ownership of our Common Stock as of February 22, 2010, of (i) all current directors and nominees for director, (ii) each executive officer named in the Summary Compensation Table presented later in this Proxy Statement, and (iii) all directors and nominees for director and executive officers as a group. As of February 22, 2010, none of the individuals or the group in the above categories owned one percent (1%) or more of our voting securities. Unless otherwise noted, all shares of Common Stock set forth in the table are beneficially owned, directly or indirectly, with sole voting and investment power, by such shareholder.

Name	Number of Shares of Common Stock Beneficially Owned[1,2]
John D. Baker II	7,450
James E. Bostic, Jr.	8,445[1]
Harris E. DeLoach, Jr.	5,000
James B. Hyler, Jr.	1,000
William D. Johnson	136,751[2]
Robert W. Jones	1,000
W. Steven Jones	1,000
Jeffrey J. Lyash	19,393[2]
Melquiades R. "Mel" Martinez	—[3]
E. Marie McKee	3,000[1]
Mark F. Mulhern	34,550[2]
John H. Mullin, III	10,000[1]
Charles W. Pryor, Jr.	1,042
Carlos A. Saladrigas	7,000[1]
Paula J. Sims	11,766[2]
Theresa M. Stone	1,000
Alfred C. Tollison, Jr.	1,000
Lloyd M. Yates	27,937[2]
Shares of Common Stock beneficially owned by all directors and executive officers of the Company as a group (25 persons)	438,761[4]

[1] Includes shares of our Common Stock such director has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options, as follows:

Director	Stock Options
James E. Bostic, Jr.	4,000
E. Marie McKee	2,000
John H. Mullin, III	6,000
Carlos A. Saladrigas	6,000

[2] Includes shares of Restricted Stock currently held, and shares of our Common Stock such officer has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options as follows:

Officer	Restricted Stock	Stock Options
William D. Johnson	16,134	—
Jeffrey J. Lyash	3,834	—
Mark F. Mulhern	5,834	7,000
Paula J. Sims	1,000	—
Lloyd M. Yates	3,834	—

[3] Mr. Martinez was elected to the Board effective March 1, 2010 and did not own any shares of the Company's Common Stock at the time of his election. Mr. Martinez is standing for election to the Board by our shareholders for the first time.

[4] Includes shares each group member (shares in the aggregate) has the right to acquire beneficial ownership of within 60 days through the exercise of certain stock options.

Ownership of Units Representing Common Stock

The table below shows ownership of units representing our Common Stock under the Non-Employee Director Deferred Compensation Plan and units under the Non-Employee Director Stock Unit Plan as of February 22, 2010. A unit of Common Stock does not represent an equity interest in the Company, and possesses no voting rights, but is equal in economic value at all times to one share of Common Stock.

Director	Directors' Deferred Compensation Plan	Non-Employee Director Stock Unit Plan
John D. Baker II	1,339	1,489
James E. Bostic, Jr.	11,723	10,017
Harris E. DeLoach, Jr.	10,299	5,989
James B. Hyler, Jr.	1,231	3,090
Robert W. Jones	7,294	4,538
W. Steven Jones	11,911	7,522
Melquiades R. "Mel" Martinez*	67	—
E. Marie McKee	29,288	12,877
John H. Mullin, III	19,601	13,374
Charles W. Pryor, Jr.	2,147	4,538
Carlos A. Saladrigas	6,993	11,013
Theresa M. Stone	10,087	7,522
Alfred C. Tollison, Jr.	9,905	5,989

* Units owned as of March 1, 2010.

The table below shows ownership as of February 22, 2010, of (i) performance units under the Long-Term Compensation Program; (ii) performance units recorded to reflect awards deferred under the Management Incentive Compensation Plan ("MICP"); (iii) performance shares awarded under the Performance Share Sub-Plan of the 1997, 2002 and 2007 Equity Incentive Plans ("PSSP") (see "Outstanding Equity Awards at Fiscal Year-End Table" on page 51); (iv) units recorded to reflect awards deferred under the PSSP; (v) replacement units representing the value of our contributions to the 401(k) Savings & Stock Ownership Plan that would have been made but for the deferral of salary under the Management Deferred Compensation Plan and contribution limitations under Section 415 of the

Internal Revenue Code of 1986, as amended; and (vi) Restricted Stock Units ("RSUs") awarded under the 2002 and 2007 Equity Incentive Plans.

Officer	Long-Term Compensation Program	MICP	PSSP	PSSP Deferred	MDCP	RSUs
William D. Johnson	—	1,711	146,294	—	1,059	66,001
Jeffrey J. Lyash	—	—	36,289	—	314	25,398
Mark F. Mulhern	—	3,853	28,308	2,452	—	20,942
Paula J. Sims	—	7,347	26,621	1,512	—	19,617
Lloyd M. Yates	—	2,672	36,132	6,376	158	25,325

TRANSACTIONS WITH RELATED PERSONS

There were no transactions in 2009, and there are no currently proposed transactions involving more than $120,000, in which the Company or any of its subsidiaries was or is to be a participant and in which any of the Company's directors, executive officers, nominees for director or any of their immediate family members had a direct or indirect material interest.

Our Board of Directors has adopted policies and procedures for the review, approval or ratification of Related Person Transactions under Item 404(a) of Regulation S-K (the "Policy"), which is attached to this Proxy Statement as Exhibit A. The Board has determined that the Governance Committee is best suited to review and approve Related Person Transactions because the Governance Committee oversees the Board of Directors' assessment of our directors' independence. The Governance Committee will review and may recommend to the Board amendments to this Policy from time to time.

For the purposes of the Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness (or any series of similar transactions, arrangements or relationships), in which we (including any of our subsidiaries) were, are or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. The term "Related Person" is defined under the Policy to include our directors, executive officers, nominees to become directors and any of their immediate family members.

Our general policy is to avoid Related Person Transactions. Nevertheless, we recognize that there are situations where Related Person Transactions might be in, or might not be inconsistent with, our best interests and those of our shareholders. These situations could include (but are not limited to) situations where we might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to Related Persons on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. In determining whether to approve or disapprove each Related Person Transaction, the Governance Committee considers various factors, including (i) the identity of the Related Person; (ii) the nature of the Related Person's interest in the particular transaction; (iii) the approximate dollar amount involved in the transaction; (iv) the approximate dollar value of the Related Person's interest in the transaction; (v) whether the Related Person's interest in the transaction conflicts with his obligations to the Company and its shareholders; (vi) whether the transaction will provide the Related Person with an unfair advantage in his dealings with the Company; and (vii) whether the transaction will affect the Related Person's ability to act in the best interests of the Company and its shareholders. The Governance Committee will only approve those Related Person Transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers to file reports of their holdings and transactions in our securities with the SEC and the NYSE. Based on our records and other information, we believe that all Section 16(a) filing requirements applicable to our directors and executive officers with respect to the Company's 2009 fiscal year were met, except as follows: James Scarola inadvertently failed to timely file a Form 4 related to the deferral, in 2009 and 2010, of portions of two awards granted under the Company's Management Incentive Compensation Plan. A Form 4 reporting both transactions was filed on March 16, 2010. Paula J. Sims inadvertently failed to file on a timely basis a Form 4 with respect to the deferral in 2009 of a portion of an award granted under the Company's Management Incentive Compensation Plan. A Form 4 reporting the transaction was filed on March 16, 2010. Additionally, with regard to the Company's 2010 fiscal year, each of Jeffrey A. Corbett, Vincent M. Dolan, William D. Johnson, Michael A. Lewis, Jeffrey J. Lyash, John R. McArthur, Mark F. Mulhern, James Scarola, Frank A. Schiller, Paula J. Sims, Jeffrey M. Stone and Lloyd M. Yates inadvertently failed to file on a timely basis a Form 4 with respect to the payout of performance units granted under the Company's Performance Share Sub-Plan. A Form 4 reporting the transaction was filed by each individual on March 11, 2010.

CORPORATE GOVERNANCE GUIDELINES AND CODE OF ETHICS

The Board of Directors operates pursuant to an established set of written Corporate Governance Guidelines (the "Governance Guidelines") that set forth our corporate governance philosophy and the governance policies and practices we have implemented in support of that philosophy. The three core governance principles the Board embraces are integrity, accountability and independence.

The Governance Guidelines describe Board membership criteria, the Board selection and orientation process and Board leadership. The Governance Guidelines require that a minimum of 80 percent of the Board's members be independent and that the membership of each Board committee, except the Executive Committee, consist solely of independent directors. Directors who are not full-time employees of the Company must retire from the Board at age 73. Directors whose job responsibilities or other factors relating to their selection to the Board change materially after their election are required to submit a letter of resignation to the Board. The Board will have an opportunity to review the continued appropriateness of the individual's Board membership under these circumstances, and the Governance Committee will make the initial recommendation as to the individual's continued Board membership. The Governance Guidelines also describe the stock ownership guidelines that are applicable to Board members and prohibit compensation to Board members other than directors' fees and retainers.

The Governance Guidelines provide that the Organization and Compensation Committee of the Board will evaluate the performance of the Chief Executive Officer on an annual basis, using objective criteria, and will communicate the results of its evaluation to the full Board. The Governance Guidelines also provide that the Governance Committee is responsible for conducting an annual assessment of the performance and effectiveness of the Board, and its standing committees, and reporting the results of each assessment to the full Board annually.

The Governance Guidelines provide that Board members have complete access to our management and can retain, at our expense, independent advisors or consultants to assist the Board in fulfilling its responsibilities, as it deems necessary. The Governance Guidelines also state that it is the Board's policy that the nonmanagement directors meet in executive session on a regularly scheduled basis. Those sessions are chaired by the Lead Director, John H. Mullin, III, who is also Chair of the Governance Committee. He can be contacted by writing to John H. Mullin, III, Lead Director, Progress Energy, Inc. Board of Directors, c/o John R. McArthur, Executive Vice President and Corporate Secretary, P.O. Box 1551, Raleigh, North Carolina 27602-1551. We screen mail addressed to Mr. Mullin for security purposes and to ensure that it relates to discrete business matters relevant to the Company. Mail addressed to Mr. Mullin that satisfies these screening criteria will be forwarded to him.

In keeping with the Board's commitment to sound corporate governance, we have adopted a comprehensive written Code of Ethics that incorporates an effective reporting and enforcement mechanism. The Code of Ethics is applicable to all of our employees, including our Chief Executive Officer, our Chief Financial Officer and our Controller. The Board has adopted the Company's Code of Ethics as its own standard. Board members, our officers and our employees certify their compliance with our Code of Ethics on an annual basis.

Our Governance Guidelines and Code of Ethics are posted on our Internet Web site and can be accessed at *www.progress-energy.com/investor.*

DIRECTOR INDEPENDENCE

The Board of Directors has determined that the following current members of the Board are independent, as that term is defined under the general independence standards contained in the listing standards of the NYSE:

John D. Baker II	E. Marie McKee
James E. Bostic, Jr.	John H. Mullin, III
Harris E. DeLoach, Jr.	Charles W. Pryor, Jr.
James B. Hyler, Jr.	Carlos A. Saladrigas
Robert W. Jones	Theresa M. Stone
W. Steven Jones	Alfred C. Tollison, Jr.
Melquiades R. "Mel" Martinez	

Additionally, the Board of Directors has determined that David L. Burner, who served as a member of the Board during a portion of 2009, was independent as that term is defined under the general independence standards contained in the NYSE's listing standards. In addition to considering the NYSE's general independence standards, the Board has adopted categorical standards to assist it in making determinations of independence. The Board's categorical independence standards are outlined in our Governance Guidelines. The Governance Guidelines are available on our Internet Web site and can be accessed at *www.progress-energy.com/investor*. All directors, former directors and director nominees identified as independent in this Proxy Statement meet these categorical standards.

In determining that the individuals named above are or were independent directors, the Governance Committee considered their involvement in various ordinary course commercial transactions and relationships. During 2009, Ms. McKee and Messrs. DeLoach and Mullin served as officers and/or directors of companies that have been among the purchasers of the largest amounts of electric energy sold by PEC during the last three preceding calendar years. Messrs. Baker, Mullin and Saladrigas served as officers and/or directors of companies that purchase electric energy from PEF. Mr. Robert W. Jones was an employee of Morgan Stanley through May 2009. Morgan Stanley has provided a variety of investment banking services to us during the past several years; however, Mr. Jones had no direct or indirect material interests or involvement in transactions between the Company and Morgan Stanley. Mr. Jones is no longer a Morgan Stanley employee although his firm provides services to Morgan Stanley. Mr. W. Steven Jones serves as a director of a communications technology company that provided services to us in 2009. Mr. Baker currently serves as a director of Wells Fargo & Company and is a former director of Wachovia Corporation. Both of these entities have been part of our core bank group and have provided a variety of banking and investment services to us during the past several years. Mr. Pryor is a director of a company that has affiliates that provide uranium enrichment services to PEC and PEF. Mr. Tollison is a former employee of PEC and thus receives a modest pension from us. All of the described transactions were ordinary course commercial transactions conducted at arm's length and in compliance with the NYSE's standards for director independence. In addition, the Governance Committee considers the relationships our directors have with tax-exempt organizations that receive contributions from the Company. The Governance Committee considered each of these transactions and relationships and determined that none of them was material or affected the independence of the directors involved under either the general independence standards contained in the NYSE's listing standards or our categorical independence standards.

BOARD, BOARD COMMITTEE AND ANNUAL MEETING ATTENDANCE

The Board of Directors is currently comprised of fourteen (14) members. The Board of Directors met six times in 2009. Average attendance of the directors at the meetings of the Board and its committees held during 2009 was 90 percent, and no director attended less than 80 percent of all Board and his/her respective committee meetings held in 2009.

Our Company expects all directors to attend its annual meetings of shareholders. Such attendance is monitored by the Governance Committee. All directors who were serving as directors as of May 13, 2009, the date of the 2009 Annual Meeting of Shareholders, attended that meeting, with the exception of Mr. Burner, who retired from the Board effective May 13, 2009, and Mr. Saladrigas, who was recovering from an illness at the time of the meeting.

BOARD COMMITTEES

The Board of Directors appoints from its members an Executive Committee, an Audit and Corporate Performance Committee, a Governance Committee, a Finance Committee, a Nuclear Project Oversight Committee, an Operations and Nuclear Oversight Committee, and an Organization and Compensation Committee. The charters of all committees of the Board are posted on our Internet Web site and can be accessed at *www.progress-energy.com/investor.* The current membership and functions of the standing Board committees are discussed below.

Executive Committee

The Executive Committee is presently composed of one director who is an officer and five nonmanagement directors: Messrs. William D. Johnson—Chair, Harris E. DeLoach, Jr., Robert W. Jones, and John H. Mullin, III, and Ms. E. Marie McKee and Ms. Theresa M. Stone. The authority and responsibilities of the Executive Committee are described in our By-Laws. Generally, the Executive Committee will review routine matters that arise between meetings of the full Board and require action by the Board. The Executive Committee held no meetings in 2009.

Audit and Corporate Performance Committee

The Audit and Corporate Performance Committee (the "Audit Committee") is presently composed of the following seven nonmanagement directors: Ms. Theresa M. Stone—Chair, and Messrs. James E. Bostic, Jr., W. Steven Jones, Melquiades R. "Mel" Martinez, Charles W. Pryor, Jr., Carlos A. Saladrigas, and Alfred C. Tollison, Jr. All members of the committee are independent as that term is defined under the enhanced independence standards for audit committee members contained in the Securities Exchange Act of 1934 and the related rules, as amended, as incorporated into the listing standards of the NYSE. Mr. Saladrigas and Ms. Stone have been designated by the Board as the "Audit Committee Financial Experts," as that term is defined in the SEC's rules. The work of the Audit Committee includes oversight responsibilities relating to the integrity of our financial statements, compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm, performance of the internal audit function and of the independent registered public accounting firm, and the Corporate Ethics Program. The role of the Audit Committee is further discussed under "Report of the Audit and Corporate Performance Committee" below. The Audit Committee held seven meetings in 2009.

Corporate Governance Committee

The Governance Committee is presently composed of the following five nonmanagement directors: Messrs. John H. Mullin, III—Chair/Lead Director, Harris E. DeLoach, and Robert W. Jones, and Ms. E. Marie McKee and Ms. Theresa M. Stone. All members of the Governance Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Governance Committee is responsible for making recommendations to the Board with respect to the governance of the Company and the Board. Its responsibilities include recommending amendments to our Charter and By-Laws, making recommendations regarding the structure, charter, practices and policies of the Board, ensuring that processes are in place for annual Chief Executive Officer performance appraisal and review of succession planning and management development, recommending a process for the annual assessment of Board performance, recommending criteria for Board membership, reviewing the qualifications of and recommending to the Board nominees for election. The Governance Committee is responsible for conducting investigations into or studies of matters within the scope of its responsibilities and to retain outside advisors to identify director candidates. The Governance Committee will consider qualified candidates for director nominated by shareholders at an annual meeting of shareholders, provided, however, that written notice of any shareholder nominations must be received by the Corporate Secretary of the Company no later than the close of business on the 120th calendar day before the date our Proxy Statement was released to shareholders in connection with the previous year's annual meeting. See "Future Shareholder Proposals" below for more information regarding shareholder nominations of directors. The Governance Committee held three meetings in 2009.

Finance Committee

The Finance Committee is presently composed of the following six nonmanagement directors: Messrs. Robert W. Jones—Chair, John D. Baker II, James B. Hyler, Jr., John H. Mullin, III, and Carlos A. Saladrigas, and Ms. Theresa M. Stone. The Finance Committee reviews and oversees our financial policies and planning, financial position, strategic planning and investments, pension funds and financing plans. The Finance Committee also monitors our risk management activities and financial position and recommends changes to our dividend policy and proposed budget. The Finance Committee held four meetings in 2009.

Nuclear Project Oversight Committee (*ad hoc*)

The Nuclear Project Oversight Committee is presently composed of the following six nonmanagement directors: Messrs. Charles W. Pryor, Jr.—Chair, Alfred C. Tollison, Jr.—Vice Chair, James E. Bostic, Jr., Harris E. DeLoach, Jr., and W. Steven Jones, and Ms. E. Marie McKee. The Nuclear Project Oversight Committee is an *ad hoc* committee that serves as the primary point of contact for Board oversight of the construction of new nuclear projects, and advises the Board of construction status, including schedule, cost and legal, legislative and regulatory activities. The Nuclear Project Oversight Committee held no meetings in 2009.

Operations and Nuclear Oversight Committee

The Operations and Nuclear Oversight Committee is presently composed of the following seven nonmanagement directors: Messrs. Harris E. DeLoach, Jr.—Chair, James E. Bostic, Jr., W. Steven Jones, Melquiades R. "Mel" Martinez, Charles W. Pryor, Jr., and Alfred C. Tollison, Jr., and Ms. E. Marie McKee. The Operations and Nuclear Oversight Committee reviews our load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading and term marketing, and other Company operations. The Operations and Nuclear Oversight Committee reviews and assesses our policies, procedures, and practices relative to the protection of the environment and the health and safety of our employees, customers, contractors and the public. The Operations and Nuclear Oversight Committee advises the Board and makes recommendations for the Board's consideration regarding operational, environmental and safety-related issues. The Operations and Nuclear Oversight Committee held four meetings in 2009.

Organization and Compensation Committee

The Organization and Compensation Committee (the "Compensation Committee") is presently composed of the following six nonmanagement directors: Ms. E. Marie McKee—Chair, and Messrs. John D. Baker II, Harris E. DeLoach, Jr., James B. Hyler, Jr., Robert W. Jones, and John H. Mullin, III. All members of the Compensation Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Compensation Committee verifies that personnel policies and procedures are in keeping with all governmental rules and regulations and are designed to attract and retain competent, talented employees and develop the potential of these employees. The Compensation Committee reviews all executive development plans, makes executive compensation decisions, evaluates the performance of the Chief Executive Officer and oversees plans for management succession.

The Compensation Committee may hire outside consultants, and the Compensation Committee has no limitations on its ability to select and retain consultants as it deems necessary or appropriate. Annually, the Compensation Committee evaluates the performance of its compensation consultant to assess its effectiveness in assisting the Committee with implementing the Company's compensation program and principles. For 2009, the Compensation Committee retained Hewitt Associates as its executive compensation and benefits consultant to assist the Compensation Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, in 2009, Hewitt Associates reported directly to the Compensation Committee. In January 2010, Hewitt Associates spun off its executive compensation practice into a separate entity named Meridian Compensation Partners, LLC ("Meridian"), an independent agency wholly-owned by its partners. Meridian reports directly to the Compensation Committee.

The Compensation Committee relies on its compensation consultant to advise it on various matters relating to our executive compensation and benefits program. These services include:

- Advising the Compensation Committee on general trends in executive compensation and benefits;
- Summarizing developments relating to disclosure, risk assessment process and other technical areas;
- Performing benchmarking and competitive assessments;
- Assistance in designing incentive plans;
- Performing financial analysis related to plan design and assisting the Compensation Committee in making pay decisions in light of results; and
- Recommending appropriate performance metrics and financial targets.

The Compensation Committee has adopted a policy for Pre-Approval of Compensation Consultant Services (the "Policy"). Pursuant to the Policy, the compensation consultant may not provide any services or products to the Company without the express prior approval of the Compensation Committee. The compensation consultant did not provide any services or products to the Company other than those that are provided to the Committee and that are related to the Company's executive compensation and benefits program.

The Compensation Committee's chair or the chairman of our Board of Directors may call meetings, other than previously scheduled meetings, as needed. The Compensation Committee may form subcommittees for any purpose that the Compensation Committee deems appropriate and may delegate to such subcommittees such power and authority as the Compensation Committee deems appropriate. Appropriate executive officers of the Company ensure that the Compensation Committee receives administrative support and assistance, and make recommendations to the Committee to ensure that compensation plans are aligned with our business strategy and compensation philosophy. John R. McArthur, our Executive Vice President and Corporate Secretary, serves as management's liaison to the Compensation Committee. William D. Johnson, our Chief Executive Officer, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Compensation Committee regarding those executives' compensation.

The Compensation Committee held seven meetings in 2009.

Compensation Committee Interlocks and Insider Participation

None of the directors who served as members of the Compensation Committee during 2009 was our employee or former employee and none of them had any relationship requiring disclosure under Item 404 of Regulation S-K. During 2009, none of our executive officers served on the compensation committee (or equivalent), or the board of directors of another entity whose executive officer(s) served on our Compensation Committee or Board of Directors.

DIRECTOR NOMINATING PROCESS AND COMMUNICATIONS WITH BOARD OF DIRECTORS

Governance Committee

The Governance Committee performs the functions of a nominating committee. The Governance Committee's Charter describes its responsibilities, including recommending criteria for membership on the Board, reviewing qualifications of candidates and recommending to the Board nominees for election to the Board. As noted above, the Governance Guidelines contain information concerning the Committee's responsibilities with respect to reviewing with the Board on an annual basis the qualification standards for Board membership and identifying, screening and recommending potential directors to the Board. All members of the Governance Committee are independent as defined under the general independence standards of the NYSE's listing standards. Additionally, the Governance Guidelines require that all members of the Governance Committee be independent.

Director Candidate Recommendations and Nominations by Shareholders

Shareholders should submit any director candidate recommendations in writing in accordance with the method described under "Communications with the Board of Directors" below. Any director candidate recommendation that is submitted by one of our shareholders to the Governance Committee will be acknowledged, in writing, by the Corporate Secretary. The recommendation will be promptly forwarded to the Chair of the Governance Committee, who will place consideration of the recommendation on the agenda for the Governance Committee's regular December meeting. The Governance Committee will discuss candidates recommended by shareholders at its December meeting and present information regarding such candidates, along with the Governance Committee's recommendation regarding each candidate, to the full Board for consideration. The full Board will determine whether it will nominate a particular candidate for election to the Board.

Additionally, in accordance with Section 11 of our By-Laws, any shareholder of record entitled to vote for the election of directors at the applicable meeting of shareholders may nominate persons for election to the Board of Directors if that shareholder complies with the notice procedure set forth in the By-Laws and summarized in "Future Shareholder Proposals" below.

Governance Committee Process for Identifying and Evaluating Director Candidates

The Governance Committee evaluates all director candidates, including those nominated or recommended by shareholders, in accordance with the Board's qualification standards, which are described in the Governance Guidelines. The Committee evaluates each candidate's qualifications and assesses them against the perceived needs of the Board. Qualification standards for all Board members include: integrity; sound judgment; independence as defined under the general independence standards contained in the NYSE listing standards and the categorical standards adopted by the Board; financial acumen; strategic thinking; ability to work effectively as a team member; demonstrated leadership and excellence in a chosen field of endeavor; experience in a field of business; professional or other activities that bear a relationship to our mission and operations; appreciation of the business and social environment in which we operate; an understanding of our responsibilities to shareholders, employees, customers and the communities we serve; and service on other boards of directors that would not detract from service on our Board.

Although the Company does not have an official policy regarding the consideration of diversity in identifying director nominees, diversity is among the factors that are considered in selecting Board nominees. The Company values diversity among its Board members and seeks to create a Board that reflects the demographics of the areas we serve, and includes a complimentary mix of individuals with diverse backgrounds, viewpoints, professional experiences, education and skills that reflect the broad set of challenges the Board confronts.

Communications with the Board of Directors

The Board has approved a process for shareholders and other interested parties to send communications to the Board. That process provides that shareholders and other interested parties can send communications to the Board and, if applicable, to the Governance Committee or to specified individual directors, including the Lead Director, in writing c/o John R. McArthur, Executive Vice President and Corporate Secretary, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551.

We screen mail addressed to the Board, the Governance Committee or any specified individual director for security purposes and to ensure that the mail relates to discrete business matters relevant to the Company. Mail that satisfies these screening criteria is forwarded to the appropriate director.

BOARD LEADERSHIP STRUCTURE AND ROLE IN RISK OVERSIGHT

Board Leadership

Our Governance Guidelines allow the Board to select a Chairman based on the needs of the Company at the time. The Board may appoint the Chief Executive Officer or it may choose another director for the Chairman position. Thus, the Board has the authority to separate the Chairman and Chief Executive Officer positions if it chooses to do so, but it is not required to do so.

Currently, the Board believes that the Company's interests are best served by having the Chief Executive Officer also serve as Chairman because it allows the Board to most effectively and directly leverage the Chief Executive Officer's day-to-day familiarity with the Company's operations. This is particularly beneficial for the Board at this time given the rapidly evolving nature of the energy industry and the complexity of the projects being considered by the Company, including the construction of new nuclear facilities.

Our Governance Guidelines provide that if the Chief Executive Officer currently holds the position of Chairman, then the full Board shall appoint an independent director to serve as Chair of the Governance Committee and Lead Director of the Board. The clearly delineated and comprehensive duties of the Lead Director include presiding over all meetings of the Board at which the Chairman is not present, including executive sessions and other meetings of the non-management and independent directors and serving as liaison and facilitating communication between the independent directors and the Chairman. The Lead Director also provides input to the Chairman and CEO with respect to information sent to the Board and the agendas and schedules for Board and committee meetings. Any independent director, including the Lead Director, has the authority to call meetings of the independent directors. If requested by major shareholders, the Lead Director is available for consultation and direct communication. In addition, the Lead Director serves as a mentor and advisor to the Chairman and Chief Executive Officer and assures that the Chairman and Chief Executive Officer understands the Board's views on critical matters. Pursuant to the Governance Guidelines, Mr. Mullin, an independent director and Chair of the Governance Committee, has served as Lead Director of the Board since 2004.

In our view, our current leadership structure has fostered sound corporate governance practices and strong independent Board leadership that have benefitted the Company and its shareholders.

Board Role in Risk Oversight

We have established a risk management framework that is the backbone for risk management activities that occur across Progress Energy. The framework establishes processes for identifying, measuring, managing and monitoring risk across the Company and its subsidiaries. We also maintain an ongoing inventory that details risk types, the internal department that manages each type of risk and the Board committees that are involved in overseeing those activities. Our Chief Executive Officer and Senior Management have responsibility for assessing and managing the Company's exposure to risk. In this regard, we have established a Risk Management Committee, comprised of various senior executives, that provides guidance and direction in the identification and management of financial risks. The Board is not involved in the Company's day-to-day risk management activities; however, the various Board Committees are involved in different aspects of overseeing those activities.

The Audit and Corporate Performance Committee is responsible for ensuring that appropriate guidelines and controls are in place and reviews the framework for managing risk and adherence to that framework. The Audit and Corporate Performance Committee reviews and discusses with management the Company's guidelines and polices governing risk assessment and risk management.

The Finance Committee is responsible for the oversight of the Risk Management Committee Policy and Guidelines. It oversees the financial risks associated with guarantees, risk capital, corporate financing activities and debt structure. The Finance Committee ensures that dollar amounts and limits are managed within the established framework. The Finance Committee reports to the full Board at least once a quarter.

The Operations and Nuclear Oversight Committee is charged with oversight of risks related to operations and environmental and health and safety issues.

The Organization and Compensation Committee is responsible for the oversight of risks that can result from personnel issues and misalignment between compensation and performance plans and the interests of the Company's shareholders.

The enterprise risk management program is reviewed with the Board on an annual basis. Our risk management framework is designed to enable the Board to stay informed about and understand the key risks facing the Company, understand how those risks relate to the Company's business and strategy, and the steps the Company is taking to manage those risks.

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis ("CD&A") has four parts. The first part describes the Company's executive compensation philosophy and provides an overview of the compensation program and process. The second part describes each element of the Company's executive compensation program. The third part describes how the Organization and Compensation Committee of the Company's Board of Directors (in this CD&A, the "Committee") applied each element to determine the compensation paid to each of the named executive officers in the Summary Compensation Table on page 45 (the "named executive officers") for the services they provided to the Company in 2009. For 2009, the Company's named executive officers were:

- William D. Johnson, Chairman, President and Chief Executive Officer;
- Mark F. Mulhern, Senior Vice President and Chief Financial Officer;
- Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, Progress Energy Florida, Inc. (PEF));
- Lloyd M. Yates, President and Chief Executive Officer, Progress Energy Carolinas, Inc. (PEC); and
- Paula J. Sims, Senior Vice President – Power Operations.

The fourth part consists of the Committee's Report.

Following the CD&A are the tables setting forth the 2009 compensation for each of the named executive officers, as well as a discussion concerning compensation for the members of the Company's Board of Directors. Throughout this CD&A, the Company is at times referred to as "we," "our" or "us."

I. COMPENSATION PHILOSOPHY AND OVERVIEW

We are an integrated electric utility primarily engaged in the regulated utility business. Our executive compensation philosophy is designed to provide competitive and reasonable compensation consistent with the three key principles that we believe are critical to our long-term success as described below:

- **Aligning the interests of shareholders and management.** We believe that our major shareholders invest in the Company because they believe we can produce average annual total shareholder return in the 7% to 10% range over the long term. Total shareholder return is defined as the stock price appreciation plus dividends over the period, divided by the share price at the beginning of the measurement period. Further, our investors do not expect or desire significant volatility in our stock price. Accordingly, our executive compensation program is designed to encourage management to lead our Company in a way that consistently produces earnings per share growth and a competitive dividend yield. In the two years since Mr. Johnson became our Chief Executive Officer, under his leadership and that of the Committee, many actions have been taken to align the executive compensation structure with our shareholders' interests. These actions include a significant reduction of perquisites for both our executive officers and non-executive officers who are in senior management; an increase in the stock ownership guidelines; implementation of a new performance measure in the Management Incentive Compensation Plan ("MICP") to further enhance transparency and alignment of performance and payouts for executive officers and non-executive officers in senior management; and a modification of our Performance Share Sub-Plan ("PSSP") to closely align awards under that plan to our operating results, actual total shareholder returns, and, with respect to our peers, relative total shareholder returns.

- **Rewarding operating performance results that are consistent with reliable and efficient electric service.** We believe that to achieve this goal over the long term, we must:
  - deliver high levels of customer satisfaction;
  - operate our systems reliably and efficiently;
  - maintain a constructive regulatory environment;
  - have a productive, engaged and highly motivated workforce;
  - meet or exceed our operating plans and budgets;
  - be a good corporate citizen; and
  - produce value for our investors.

Therefore, we determine base salary levels and annual incentive compensation based on corporate performance in these areas, along with individual contribution and performance.

- **Attracting and retaining an experienced and effective management team.** The competition for skilled and experienced management is significant in the utility industry. We believe that the management of our business requires executives with a variety of experiences and skills. We expect the competition for talent to continue to intensify, particularly in the nuclear, renewable energy sources, and emerging technologies areas, as the industry enters a significant capital expenditure phase and the requirement for reliable and environmentally responsible generating capacity increases. To address this issue, we have designed market-based compensation programs that are competitive and are aligned with our corporate strategy.

Consistent with these principles, the Committee seeks to provide executive officers a compensation program that is competitive in the market place and provides incentives necessary to motivate executives to perform in the best interests of the Company and its shareholders.

In determining an individual executive officer's compensation opportunity, the Committee believes that it must be competitive within the marketplace for each particular executive officer. As such, the compensation opportunities vary significantly from individual to individual based on the specific nature of the executive position. For example, our Chief Executive Officer is responsible for the overall performance of the Company and, as such, his position has a greater scope of responsibility than our other executive positions and is benchmarked accordingly. From a market perspective, the position of chief executive officer receives a greater compensation opportunity than other executive positions. The Committee therefore sets our Chief Executive Officer's compensation opportunity at levels that reflect the responsibilities of his position and the Committee's expectations.

ASSESSMENT OF RISK

Our Company is highly regulated at both the federal and state levels, and therefore significant swings in earnings performance or growth over time are less influenced by any particular individual or groups of individuals. We believe the variable components of our compensation program for executive officers do not incentivize excessive risk taking for the following reasons:

- Our incentive compensation practices do not reward the executive officers for meeting or exceeding volume or revenue targets.

- Our compensation program is evaluated annually for its effectiveness and consistency with the Company's goals without promoting excessive risk.
- Our compensation program appropriately balances short- and long-term incentives with approximately 60% of total target compensation for the executive officers provided in equity and focused on long-term performance.
- The PSSP rewards significant and sustainable performance over the longer term by focusing on three-year earnings per share growth and relative total shareholder return targets.
- The MICP in effect for 2009 specifically focuses on earnings before interest, taxes, depreciation and amortization ("EBITDA"), and the MICP that is in effect for 2010 specifically focuses on legal entity net income, because we believe that these are appropriate measures to assess the intrinsic value of the Company to determine whether the Company has been successful in its fundamental business.
- Our compensation programs are designed to make it difficult for any one person to meaningfully influence his or her own incentive award.
- The executive officers receive restricted stock units that generally have a three-year vesting period so that their upside potential and downside risk are aligned with that of our shareholders and promote long-term performance over the vesting period.
- The executive officers are subject to stock ownership guidelines independently set by the Board to reflect the compensation program's goals of risk assumption and sharing between executives and shareholders.

We have determined that the compensation program for non-executive officers who are in senior management positions does not encourage excessive risk taking for all the reasons stated above.

COMPENSATION PROGRAM STRUCTURE

The table below summarizes the current elements of our executive compensation program.

Element	Brief Description	Primary Purpose	Short- or Long-Term Focus
Base Salary	Fixed compensation. Annual merit increases reward individual performance and growth in the position.	Basic element of compensation and necessary to attract and retain.	Short-term (annual)
Annual Incentive	Variable compensation based on achievement of annual performance goals.	Rewards operating performance results that are consistent with reliable and efficient electric service.	Short-term (annual)
Long-Term Incentives — Performance Shares	Variable compensation based on achievement of long-term performance goals.	Align interests of shareholders and management and aid in attracting and retaining executives.	Long-term
Long-Term Incentives — Restricted Stock/Restricted Stock Units	Fixed compensation based on target levels. Service-based vesting.	Align interests of shareholders and management and essential in attracting and retaining executives.	Long-term
Supplemental Senior Executive Retirement Plan	Formula-based compensation, based on salary, annual incentives and eligible years of service.	Provides long-term retirement benefit influenced by service and performance. Aids in attracting and retaining executives.	Long-term
Management Change-In-Control Plan	Elements based on specific plan eligibility.	Aligns interests of shareholders and management and aids in (i) attracting executives; (ii) retaining executives during transition following a change-in-control; and (iii) focusing executives on maximizing value for shareholders.	Long-term
Employment Agreements	Define Company's relationship with its executives and provide protection to each of the parties in the event of termination of employment.	Aid in attracting and retaining executives.	Long-term
Executive Perquisites	Personal benefits awarded outside of base pay and incentives.	Aid in attracting and retaining executives.	Short-term (annual)
Other Broad-Based Benefits	Employee benefits such as health and welfare benefits, 401(k) and pension plan.	Basic elements of compensation expected in the marketplace. Aid in attracting and retaining executives.	Both Short- and Long-term
Deferred Compensation	Provides executives with tax deferral options in addition to those available under our qualified plans.	Aids in attracting and retaining executives.	Long-term

The Committee believes these various compensation program elements:

- link compensation with our short- and long-term success by using operating and financial performance measures in determining payouts for annual and long-term incentive plans;
- align management interests with investor expectations by rewarding executives for delivering long-term total shareholder return;
- attract and retain executives by maintaining compensation that is competitive with our peer group;
- foster effective teamwork and collaboration between executives working in different areas to support our core values, strategy and interests;
- comply in all material respects with applicable laws and regulations; and
- can be readily understood by us, the Committee, our executives and our shareholders, and therefore are effective in meeting our business objectives.

PROGRAM ADMINISTRATION

Our executive compensation program is administered by the Committee, which is composed of six independent directors (as defined under the NYSE Corporate Governance Rules). Members of the Committee currently do not receive compensation under any compensation program in which our executive officers participate. For a discussion of director compensation, see the "Director Compensation" section on page 69 of this Proxy Statement.

The Committee's charter authorizes the Committee to hire outside consultants, and the Committee has no limitations on its ability to select and retain consultants as it deems necessary or appropriate. The Committee evaluates the performance of its compensation consultant annually to assess the consultant's effectiveness in assisting the Committee with implementing the Company's compensation program and principles. The Committee retained Hewitt Associates ("Hewitt") as its independent executive compensation consultant to assist the Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, in 2009 Hewitt reported directly to the Committee. In January 2010, Hewitt spun off its executive compensation practice into a separate entity named Meridian Compensation Partners, LLC ("Meridian"), an independent agency wholly-owned by its partners. Meridian reports directly to the Committee.

The Committee relies on its compensation consultant to advise it on various matters relating to our executive compensation and benefits program. These services include:

- advising the Committee on general trends in executive compensation and benefits;
- summarizing developments relating to disclosure, risk assessment process and other technical areas;
- performing benchmarking and competitive assessments;
- assistance in designing incentive plans;
- performing financial analysis related to plan design and assisting the Committee in making pay decisions in light of results; and
- recommending appropriate performance metrics.

Hewitt did not provide any services or products to the Company other than those provided to the Committee and related to the Company's executive compensation and benefits program. Meridian solely provides executive compensation advisory services to the Committee and provides no other services to the Committee or the Company.

Our executive officers meet with the compensation consultant to ensure the consultant understands the Company's business strategy. In addition, the executive officers ensure that the Committee receives administrative support and assistance, and make recommendations to the Committee to ensure that compensation plans are aligned with our business strategy and meet the principles described above. John R. McArthur, our Executive Vice President, serves as management's liaison to the Committee. Our executive officers and other Company employees provide the consultant with information regarding our executive compensation plans and benefits and how we administer them on an as-needed basis. William D. Johnson, our Chief Executive Officer, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Committee regarding those executives' compensation. The Committee conducts an annual performance evaluation of Mr. Johnson.

COMPETITIVE POSITIONING PHILOSOPHY

The Committee's compensation philosophy is to establish target compensation opportunities near the 50th percentile of the market, with flexibility to pay higher or lower amounts based on individual and corporate performance. The Committee believes that this philosophy is aligned with our executive compensation objective of linking pay to actual performance.

When we set and benchmark compensation for our executives against a peer group, we focus on "target" compensation. Target compensation is the value of a pay opportunity as of the beginning of the year. For short-term incentives, this means the value of that incentive opportunity based on the target percentage of salary if our performance objectives are achieved. For example, the Chief Executive Officer's target incentive opportunity is 85% of salary. This means if we reach our target financial objectives for the year, a target incentive award would likely be paid. Correspondingly, if performance should fall short or rise above these goals then the earned incentive award would typically be lesser or greater than target. In any event, target incentive opportunities are not a certainty but are a function of business results. For the performance shares, the ultimate value of any earned award is entirely a function of performance against the pre-established 3-year performance goals as well as the value of the underlying stock price. Also, for the restricted shares the value of any earned award is a function of extended service and the value of the underlying stock price. The target value is not a certainty but only the value of the opportunity.

What ultimately might be earned from either short- or long-term incentives is a function of performance and extended service. We do not benchmark realized values from our programs. With respect to our variable pay programs it is generally not the Company's purpose to deliver comparable pay outcomes since outcomes can differ by company based on their performance. Our general compensation objective is to deliver comparable pay opportunities. Realized results will then be a significant function of performance and extended service. This is a common convention among companies; nonetheless, it is an important context to consider when reviewing the remainder of this CD&A where regular references to targets and/or grant date values for our compensation programs appear.

Progress Energy, a regulated electric utility holding company, is considered to be part of the broader industry classification of electric utilities. The Company is included in several well-publicized indices, including the S&P Electric Index and the Philadelphia Utility Index. Over the past decade, as deregulation has occurred in several geographic areas of the United States, the investor community has separated the utility industry into a number of subsectors. The two main themes of separation are the aspect of the value chain in which the company participates (generation, transmission and/or delivery), and how much of its business is governed by rate-of-return regulation as opposed to competitive markets.

Thus, the industry now has subsectors identified frequently as competitive merchant, regulated delivery, regulated integrated, and unregulated integrated (typically state-regulated delivery and unregulated generation). Each of these subsectors typically differs in financial performance and market valuation characteristics such as earnings multiples, earnings growth prospects and dividend yields.

Progress Energy generally is identified as being in the regulated integrated subsector. This means Progress Energy and its peer companies are primarily rate-of-return regulated, operate in the full range of the value chain, and typically have requirements to serve all customers under state utility regulations. Other companies that are similar to us from a business model perspective and that are generally categorized in our subsector include companies like Southern Company, Duke Energy, SCANA, Xcel and PG&E. The Committee, therefore, monitors companies like these in comparing and evaluating Progress Energy's financial performance for investors and compensation for executives.

On an annual basis, the Committee's compensation consultant provides the Committee with a written analysis comparing base salaries, target annual incentives and the grant date value of long-term incentives of our executive officers to compensation opportunities provided to executive officers of our peers. For 2009, the Committee approved the use of the same peer group of 18 integrated utilities used in the prior year (that is, utilities that have transmission, distribution and generation assets) (the "Benchmarking Peer Group"). The Benchmarking Peer Group was chosen based primarily on revenues. These companies would likely be companies with which we primarily compete for executive talent. The table below lists the companies in the Benchmarking Peer Group.

Allegheny Energy, Inc.	Edison International	Pinnacle West Capital Corporation
Ameren Corporation	Entergy Corporation	PPL Corporation
American Electric Power Co., Inc.	Exelon Corporation	SCANA Corporation
Dominion Resources, Inc.	FirstEnergy Corporation	Southern Company
DTE Energy Company	FPL Group, Inc.	TECO Energy, Inc.
Duke Energy Corporation	PG&E Corporation	Xcel Energy, Inc.

The Committee will annually evaluate the Benchmarking Peer Group to ensure that it remains appropriate for compensation comparisons.

SECTION 162(m) IMPACTS

Section 162(m) of the Internal Revenue Code of 1986, as amended, limits, with certain exceptions, the amount a publicly held company may deduct each year for compensation over $1 million paid or accrued with respect to its chief executive officer and any of the other three most highly compensated officers (excluding the chief financial officer). Certain performance-based compensation is, however, specifically exempt from the deduction limit. To qualify as performance-based, compensation must be paid pursuant to a plan that is:

- administered by a committee of outside directors;
- based on achieving objective performance goals; and
- disclosed to and approved by the shareholders.

The Committee considers the impact of Section 162(m) when designing executive compensation elements and attempts to minimize nondeductible compensation. The Company received shareholder approval of the Progress Energy 2009 Executive Incentive Plan (the "EIP"), an annual cash incentive plan for the Company's named executive officers, at its 2009 Annual Meeting of Shareholders. The MICP and EIP were designed to work together to enable the Company to preserve the tax deductibility of incentive awards under Section 162(m) of the Internal Revenue Code, as amended, to the extent practicable. The sole purpose of the EIP is to preserve the tax deductibility of incentive awards that are qualified performance-based compensation.

STOCK OWNERSHIP GUIDELINES

To align the interests of our executives with the interests of shareholders, the Board of Directors utilizes stock ownership guidelines for all executive officers. The guidelines are designed to ensure that our management maintains a significant ownership stake in the Company. The guidelines require each senior executive to own a multiple of his or her base salary in the form of Company common stock generally within five years of assuming his or her position. The required levels of ownership are designed to reflect the level of responsibility that the executive positions entail.

Each year, the Committee benchmarks both the position levels and the multiples in our guidelines against those of the Benchmarking Peer Group and general industry designs. The benchmarking for 2009 indicated that the Company's guidelines were "at market" with respect to ownership levels, the types of equity that count toward ownership, and the timeframe for compliance. The stock ownership guidelines for our executive officer positions are shown in the table below:

Position Level	Stock Ownership Guidelines
Chief Executive Officer	5.0 times Base Salary
Chief Operating Officer	4.0 times Base Salary
Chief Financial Officer	3.0 times Base Salary
Presidents/Executive Vice Presidents/Senior Vice Presidents	3.0 times Base Salary

For purposes of meeting the applicable guidelines, the following are considered as common stock owned by an executive: (i) shares owned outright by the executive; (ii) stock held in any defined contribution, Employee Stock Ownership Plan or other stock-based plan; (iii) phantom stock deferred under an annual incentive or base salary deferral plan; (iv) stock earned and deferred in any long-term incentive plan account; (v) restricted stock awards and restricted stock units; and (vi) stock held in a family trust or immediate family holdings.

As of February 23, 2010, our named executive officers were in compliance with the guidelines (see Management Ownership table on page 10 of this Proxy Statement for specific details). As an indication of Mr. Johnson's alignment of his interests with that of our shareholders, he currently holds equity more than 8½-times his base salary which exceeds the 5-times base salary required under the guidelines. Further, he has not sold any of the shares he received upon the vesting of his restricted stock awards, restricted stock units, and performance shares since he became Chief Executive Officer.

II. ELEMENTS OF COMPENSATION

The various elements of our executive compensation program described above under the caption "Compensation Program Structure" on page 24 are designed to meet the three key principles described under the caption "Compensation Philosophy and Overview" on page 21 of this Proxy Statement. We have designed an allocation of long-term to short-term compensation that reflects the job responsibilities of the executive, provides an incentive for the executive to maximize his or her contribution to the Company, and is consistent with market practices. In general, we believe that the more senior an executive's position, the greater responsibility and influence he or she has regarding the long-term strategic direction of the Company. Thus, the Chief Executive Officer's target long-term compensation is designed to account for approximately two-thirds of his total compensation package (i.e., base salary, target annual incentives, and long-term incentives). By comparison, Senior Vice Presidents' target long-term compensation is designed to constitute approximately one-half of their total target compensation packages. Under this approach, executives who bear the most responsibility for and influence over the Company's long-term performance receive compensation packages that provide greater incentives to achieve the Company's long-term objectives.

The table below shows the mix of short-term and long-term incentive awards to each named executive officer for 2009. Percentages for incentives are expressed as a percentage of base salary. Additional elements of compensation are discussed further in this section.

Named Executive Officer	Base Salary (as of 1/1/10)	Short-Term (annual) Incentive Target[1]	Long-Term Incentive Targets as a Percentage of Salary		Total Incentive Target
			Performance Shares[2]	Restricted Stock	
William D. Johnson	$990,000	85%	233%	117%	435%
Mark F. Mulhern	$425,000	55%	117%	58%	230%
Jeffrey J. Lyash	$453,000	55%	117%	58%	230%
Lloyd M. Yates	$448,000	55%	117%	58%	230%
Paula J. Sims	$370,000	45%	100%	50%	195%

[1] Annual incentive awards can range from 0%-200% of target percentages noted above.

[2] Payout opportunities can range from 0%-200% of grant.

To assess overall compensation, the Committee utilizes tally sheets that provide a summary of the elements of compensation for each senior executive. The tally sheets indicate target and actual pay earned. They also summarize potential retirement benefits at age 65, current equity holdings, and potential value from severance.

1. BASE SALARY

The primary purpose of base salaries is to provide a basic element of compensation necessary to attract and retain executives. Base salary levels are established based on data from the Benchmarking Peer Group identified above and consideration of each executive officer's skills, experience, responsibilities and performance. Market compensation levels are used to assist in establishing each executive's job value (commonly called the "midpoint" at other companies). Job values serve as the market reference for determining base salaries.

Each year, the compensation consultant provides the market values for our executive officer positions. Based, in part, on these market values and, in part, on the executives' achievement of individual and Company goals, the Chief Executive Officer then recommends to the Committee base salary adjustments for our executive officers (excluding himself). The Committee reviews the proposed base salaries, adjusts them as it deems appropriate based on the executives' achievement of individual and Company goals and market trends that result in changes to job values, and approves them in the first quarter of each year. The Committee meets in executive session with the compensation consultant to review and establish the Chief Executive Officer's base salary.

The Committee's compensation philosophy is to consider market values near the 50th percentile of the Benchmarking Peer Group. The Committee may choose to set base salaries at a higher percentile of the market to address such factors as competition, retention, succession planning, and the uniqueness and complexity of a position; however, on average, base salaries of the named executive officers for 2009 were approximately 10% below those of the Benchmarking Peer Group. While our current named executive officers have significant experience and tenure with the Company, they, as a group, do not have significant tenure in their current positions. The Committee expects that over time, the average base salary percentile will continue to target the market median. We discuss how individual named executive officers' base salaries compare to the targeted benchmark in "2009 COMPENSATION DECISIONS" on page 40 below.

2. ANNUAL INCENTIVE

We sponsor the MICP, an annual cash incentive plan, in which our executives, managers and supervisors participate. The Company includes managers and supervisors in the MICP to increase accountability for all levels of the Company's management team and to better align compensation with management performance. Annual incentive opportunities are provided to executive officers to promote the achievement of annual performance objectives. MICP targets are based on a percentage of each executive's base salary and are intended to offer target award opportunities that approximate the 50th percentile of the market for Benchmarking Peer Group. For 2009, all MICP targets for our named executive officers were at or below the 50th percentile.

Each year, the Committee establishes the threshold, target and outstanding levels for the performance measures applicable to the named executive officers. The 2009 MICP performance measures were ongoing earnings per share (EPS) and business unit EBITDA for PEC and PEF as shown in the table below:

MICP Financial Performance Goals			
(in millions except EPS)	**Threshold**	**Target**	**Outstanding**
Company EPS	$2.86	$3.06	$3.16
PEC EBITDA	$1,630	$1,685	$1,715
PEF EBITDA	$1,060	$1,100	$1,115

The MICP's performance targets are designed to align with our financial plan and are intended to appropriately motivate the executive officers to achieve the desired corporate financial objectives. The potential MICP funding for each performance measure is 50% at threshold, 100% at target and 200% at outstanding (maximum). Interpolation occurs when actual performance is between the identified levels. Each performance measure is assigned a weight based on the relative importance of that measure to the Company's performance. During the year, updates are provided to the Committee on the Company's performance as compared to the performance measures. Effective January 1, 2010, the legal entity EBITDA performance measure was replaced by legal entity net income. This new performance measure was implemented as a result of the Company's desire to increase its legal entity focus on net income results. Net income results include certain regulatory decisions and key costs that are part of achieving EPS targets in managing a capital-intensive utility business.

The determination of the annual MICP award that each named executive officer receives has two steps: 1) funding the MICP awards based on the performance as compared to the financial goals specified above; and 2) determining individual MICP awards. First, the Committee determines the total amount that will be made available to fund MICP awards to managers and executives, including the named executive officers. To determine the total amount available to fund all MICP awards, we calculate an amount for each MICP participant by multiplying each participant's base salary by a performance factor (based on the sum of a participant's weighted target award achievements). The performance factor ranges between 0 and 200% of a participant's target award, depending upon the results of each applicable performance measure. The sum of these amounts for all participants is the total amount of funds available to pay to all participants, including the named executive officers. For 2009, the named executive officers' performance measures under the MICP were weighted among earnings per share and EBITDA as follows:

		Performance Measures (Relative Percentage Weight)		
Named Executive Officer	**Target Opportunity**	**Company Earnings Per Share**	**PEC EBITDA**	**PEF EBITDA**
William D. Johnson	85%	100%	—	—
Mark F. Mulhern	55%	100%	—	—
Jeffrey J. Lyash (through July 5, 2009)	55%	45%	—	55%
Jeffrey J. Lyash (effective July 6, 2009)[1]	55%	35%	32.5%	32.5%
Lloyd M. Yates	55%	45%	55%	—
Paula J. Sims	45%	35%	32.5%	32.5%

[1] Mr. Lyash's performance measure opportunities and relative weights under the MICP were adjusted effective July 6, 2009, to reflect his becoming the Company's Executive Vice President – Corporate Development.

Second, the Committee utilizes discretion to determine the MICP award to be paid to each executive. This determination is based on the executive's target award opportunity, the degree to which the Company achieved certain goals, and the executive's individual performance based on achieving individual goals and operating results.

As allowed by the MICP, the Committee uses discretion to adjust funding amounts up or down depending on factors that it deems appropriate, such as storm costs and other nonrecurring items including impairments, restructuring costs, and gains/losses on sales of assets. The Committee uses ongoing earnings per share as defined and reported by the Company in its annual earnings release. Based on management's recommendations, with respect to 2009, the Committee exercised discretion for the three performance measures—earnings per share, PEC EBITDA, and PEF EBITDA. The Committee approved adjusting earnings per share results upward by $0.04 to account for storm costs and investment gains on certain employee benefit trusts. The Committee approved adjusting the PEC EBITDA results for the decline in residential, commercial, and industrial retail usage due to weak economic conditions, favorable weather, and storm costs for a net upward adjustment of $72 million. The Committee also approved adjusting the PEF EBITDA downward by $52 million to reflect the impact of favorable weather and pension expense amortization. These adjustments resulted in earnings per share, PEC EBITDA and PEF EBITDA performance at 93%, 68% and 107% of target, respectively.

The Committee may reduce but cannot increase the amount payable to a participant according to business factors determined by the Committee, including the performance measures under the MICP. Awards are earned based upon the achievement of performance measures approved by the Committee under the MICP.

3. LONG-TERM INCENTIVES

The 2007 Equity Incentive Plan (the "Equity Incentive Plan") was approved by our shareholders in 2007 and allows the Committee to make various types of long-term incentive awards to Equity Incentive Plan participants, including the named executive officers. The awards are provided to the named executive officers to align the interests of each executive with those of the Company's shareholders. Long-term incentive awards are intended to offer target award opportunities that approximate the 50th percentile of the peer group. Currently, the Committee utilizes only two types of equity-based incentives: restricted stock units and performance shares.

The Committee has determined that to accomplish our compensation program's purposes effectively, equity-based awards should consist of one-third restricted stock units and two-thirds performance shares. This allocation reflects the Committee's strategy of utilizing long-term incentives to retain officers, align officers' interests with those of the Company's shareholders and drive specific financial performance. Performance shares are intended to focus executive officers on the multi-year sustained achievement of financial and shareholder value objectives. Restricted stock units are service-based and provide an opportunity for the executive officer's interests to be further aligned with shareholder interests if the executive remains with the Company long enough for the restricted stock units to vest.

The table below shows the 2009 long-term incentive targets for each of the named executive officer's positions.

Long-Term Incentive Award Target[1]

	Performance Shares Target Award	Restricted Stock Units Target Award
Position[2]	**2009**	**2009**
Chief Executive Officer	233%	117%
Executive Vice President	117%	58%
Chief Financial Officer	117%	58%
Presidents, PEC and PEF	117%	58%
Senior Vice Presidents	100%	50%

[1] Target award amounts are expressed as percentages of base salaries for the listed positions.

[2] Position held at Progress Energy, Inc. unless otherwise noted.

In determining long-term incentive targets, the Committee may choose to establish targets at a higher percentile of the market to address such factors as competition, retention, succession planning and the uniqueness and complexity of a position; however, on average, the targets established for the named executive officers for 2009 were 15% lower than comparable aggregate long-term incentive opportunities of our peer group. The Committee expects that, over time, the long-term incentive opportunities will continue to approximate the 50th percentile of the peer group. We discuss how individual named executive officers' long-term incentive targets compared to the targeted benchmarks in "2009 COMPENSATION DECISIONS" on page 40 below. Grants of equity-based awards typically occur in the first quarter, after the annual earnings release. This timing allows current financial information to be fully disclosed and publicly available prior to any grants.

After October 2004, we ceased granting stock options. All previously granted stock options remain valid in accordance with their terms and conditions.

Performance Shares

The PSSP authorizes the Committee to issue performance shares to executives as selected by the Committee in its sole discretion. The value of a performance share is equal to the value of a share of the Company's common stock, and earned performance share awards are paid in Company common stock. The performance period for a performance share is the three-consecutive-calendar-year period beginning in the year in which it is granted. The closing stock price on the last trading day of the year prior to the beginning of the performance period is used to calculate the number of performance shares granted to each participant in that performance period. The Committee may exercise discretion in determining the size of each performance share grant, with the maximum grant size at 125% of target. In 2009, the Committee did not exercise this discretion with respect to any grant of the named executive officers.

2007 Performance Share Sub-Plan

The PSSP, as redesigned in 2007 (the "2007 PSSP"), provides for an adjusted measure of total shareholder return to be utilized as the sole measure for determining the amount of a performance share award upon vesting. The Committee and management designed the total shareholder return performance measure to be calculated assuming a constant price to earnings ratio, which was set at the beginning of each performance period. The performance measure also uses the Company's publicly reported ongoing earnings as the earnings component for determining performance share awards. The Committee chose this method, which we will refer to as "Total Business Return," as the sole performance measure to support its desire to better align the long-term incentives with the interests of our shareholders and to emphasize our focus on dividend and earnings per share growth. The performance measure for the 2007 and 2008 performance share grants made under the 2007 PSSP are shown in the table below.

	Threshold	Target	Outstanding
2007 Total Business Return*	5%	8%	≥10.5%
2007 Percentage of Target Award Earned	50%	100%	200%
2008 Total Business Return*	5%	8%	≥11%
2008 Percentage of Target Award Earned	25%	100%	200%

* Total shareholder return, adjusted to reflect a constant price to earnings ratio set at January 1 of the grant year and to reflect the Company's ongoing earnings per share for each year of the performance period.

Additionally, the Committee retained the discretion to reduce the number of performance shares awarded if it determines that the payouts resulting from the Total Business Return do not appropriately reflect the Company's actual performance.

In 2007, the Committee approved a transition plan designed to bridge the prior long-term incentive plan to the redesigned long-term incentive plan. Under the transition plan, the Committee awarded interim grants of performance units to our officers (the "Transitional Grants"). The Transitional Grants were determined using the same Total Business Return measure as the annual grants described above.

The Transitional Grants included a grant that vested in 2009. The size of the grant awarded to each of the named executive officers was equal to such officer's revised PSSP long-term incentive target for 2007. The transition plan provides that any award from the Transitional Grants vesting in 2009 will be reduced by awards, if any, from the outstanding 2006 performance share grants vesting in 2009. Based on the performance results calculated under the terms of the 2006 PSSP, the Company did not make a payment in 2009 in connection with the performance shares that were issued in 2006. Under the terms of the Transitional Grants, the actual payout opportunity ranges from 0% to 200% of the grant, based on performance. In 2009, the Committee approved a payout of 100% of the target value for the Transitional Grant that vested in 2009.

2009 Performance Share Sub-Plan (the "2009 PSSP")

In early 2009, the Committee, along with its executive compensation consultant, concluded that the PSSP should be modified to further align it with the prevailing structure of long-term incentive plans of other highly regulated utility companies and to improve its alignment with the Company's goals. The 2009 PSSP continues to be based on a three-year performance period, and performance shares accrue quarterly dividend equivalents, which are reinvested in additional shares. Shares vest on January 1 following the end of the performance period and are paid out in Company common stock provided the performance measures have been met.

The modifications to the 2009 PSSP use two equally weighted performance measures: relative total shareholder return (TSR) and earnings growth. By using a combination of relative (TSR) and absolute (earnings growth) performance measures, the 2009 PSSP allows the Committee to consider the Company's performance as compared to the PSSP Peer Group (as defined below), and management's achievement of internal goals. TSR is defined as the appreciation or depreciation in the value of the stock, plus dividends paid during the year, divided by the closing value of the stock on the last trading day of the preceding year. The relative TSR performance is calculated using the Company's three-year annualized TSR ranked against the PSSP Peer Group (as defined below). This component of the PSSP award is based on the Company's relative TSR percentile ranking. However, regardless of the relative ranking, if the Company's TSR is negative for the performance period, no award above the threshold can be earned. The table below shows the percent of target awards that may be earned based on the Company's relative TSR percentile ranking:

Performance and Award Structure (50%)	
Percentile Ranking	**Percent of Target Award Earned**
80th	200%
50th	100%
40th	50%
<40th	0%

The Committee selected a peer group for the PSSP awards comprised of highly regulated companies with a business strategy similar to ours based on a percentage of regulated earnings (the "PSSP Peer Group"). These companies have a significant amount of their earnings generated from regulated assets. In addition, the PSSP Peer Group was selected based on other factors including revenues, market capitalization, enterprise value and percent of regulated earnings. The table below lists the companies in the PSSP Peer Group.

Alliant Energy Corporation	Great Plains Energy, Inc.	SCANA Corporation
American Electric Power, Inc.	NV Energy, Inc.	Southern Company
Consolidated Edison, Inc.	PG&E Corporation	Westar Energy, Inc.
DPL, Inc.	Pinnacle West Capital Corporation	Wisconsin Energy Corp.
Duke Energy Corporation	Portland General Electric Company	Xcel Energy, Inc.

The PSSP Peer Group differs from the Benchmarking Peer Group the Committee uses for purposes of benchmarking compensation. The Benchmarking Peer Group is a broader group that represents those companies with which we primarily compete for executive talent and includes companies that are not regulated integrated utilities. The Committee believes that for purposes of our long-term incentive plan, it is more appropriate to use the PSSP Peer Group comprised of companies that derive a significant percentage of their earnings from regulated businesses.

Earnings growth is based on the Company's ongoing annual EPS. The ongoing EPS is determined in accordance with the Company's "Policy for Press Release Earnings Disclosure." The earnings growth component of the PSSP award is based on the Company's earnings growth performance as measured against pre-established goals set at the beginning of the performance period. The table below shows the percent of target awards that may be earned based on the Company's earnings growth performance:

Performance and Award Structure (50%)		
Performance	**Three-Year Average Ongoing EPS Growth**	**Percent of Target Award Earned**
Threshold	2%	50%
Target	4%	100%
Maximum	6%	200%

Restricted Stock and Restricted Stock Units

The restricted stock component of the current long-term incentive program helps us retain executives and aligns the interests of management with those of our shareholders and management by rewarding executives for increasing shareholder value. In 2007, the Committee began issuing restricted stock units rather than restricted stock. The restricted stock units provide the same incentives and value as restricted stock, but are more flexible and cost effective for the Company. Executive officers typically receive a grant of service-based restricted stock units in the first quarter of each year which are subject to a three-year graded vesting schedule. The size of each grant is based on the executive officer's target and determined using the closing stock price on the last trading day prior to the Committee's action. The Committee establishes target levels based on the peer group information discussed under the caption "Competitive Positioning Philosophy" on page 26 above. The 2009 restricted stock unit targets for the named executive officer positions are shown in the "Long-Term Incentive Award Target" table on page 31 above. The restricted stock units pay quarterly cash dividend equivalents equal to the amount of any dividends paid on our common stock. The Committee believes that the service-based nature of restricted stock units is effective in retaining an experienced and capable management team.

To further accent the retention quality of the Equity Incentive Plan and to recognize the contribution of the officer team, including the named executive officers, the Committee may also issue in its discretion service-based ad hoc grants of restricted stock units to executives. Ad hoc grants awarded by the Committee during 2009 are discussed in "2009 COMPENSATION DECISIONS" on page 40 below.

4. SUPPLEMENTAL SENIOR EXECUTIVE RETIREMENT PLAN

The Supplemental Senior Executive Retirement Plan ("SERP") provides a supplemental, unfunded pension benefit for executive officers who have at least 10 years of service and at least three years of service on our Senior Management Committee. Currently, 11 executive officers participate in the SERP. The SERP is designed to provide pension benefits above those earned under our qualified pension plan. Current tax laws place various limits on the benefits payable under our qualified pension, including a limit on the amount of annual compensation that can be taken into account when applying the plan's benefit formulas. Therefore, the retirement incomes provided to the named executive officers by the qualified plans generally constitute a smaller percentage of final pay than is typically the case for other Company employees. To make up for this shortfall and to maintain the market-competitiveness of the Company's executive retirement benefits, we maintain the SERP for executive officers, including the named executive officers.

The SERP defines covered compensation as annual base salary plus the annual cash incentive award. The qualified plans define covered compensation as base salary only. The Committee believes it is appropriate to include annual cash incentive awards in the definition of covered compensation for purposes of determining pension plan benefits for the named executive officers to ensure that the named executive officers can replace in retirement a similar portion of total compensation as replaced for other employees who participate in the Company's pension plan. This approach takes into account the fact that base pay alone comprises a relatively smaller percentage of a named executive officer's total compensation than of other Company employees' total compensation.

The Committee believes that the SERP is a valuable and effective tool for attraction and retention due to its vesting requirements and its significant benefit. It is also a common tool among the Benchmarking Peer Group and utilities in general. Total years of service attributable to an eligible executive officer may consist of actual or deemed years. The Committee grants deemed years of service on a case-by-case basis depending upon our need to attract and retain a particular executive officer. All of our named executive officers are fully vested in the SERP.

Payments under the SERP are made in the form of an annuity, payable at age 65. The monthly SERP payment is calculated using a formula that equates to 4% per year of service (capped at 62%) multiplied by the average monthly eligible pay for the highest completed 36 months of eligible pay within the preceding 120-month period. Eligible pay includes base salary and annual incentive. (For those executives who became SERP participants on or after January 1, 2009, the target benefit percentage is 2.25% rather than 4% per year of service. None of the named executive officers for 2009 is subject to the new benefit percentage.) Benefits under the SERP are fully offset by Social Security benefits and by benefits paid under our qualified pension plan. An executive officer who is age 55 or older with at least 15 years of service may elect to retire and commence his or her SERP benefit prior to age 65. The early retirement benefit will be reduced by 2.5% for each year the participant receives the benefit prior to reaching age 65.

5. MANAGEMENT CHANGE-IN-CONTROL PLAN

We sponsor a Management Change-In-Control Plan (the "CIC Plan") for selected employees. The purpose of the CIC Plan is to retain key management employees who are critical to the negotiation and subsequent success of any transition resulting from a change-in-control ("CIC") of the Company. Providing such protection to executive officers in general minimizes disruption during a pending or anticipated CIC. Under our CIC Plan, we generally define a CIC as occurring at the earliest of the following:

- the date any person or group becomes the beneficial owner of 25% or more of the combined voting power of our then outstanding securities; or
- the date a tender offer for the ownership of more than 50% of our then outstanding voting securities is consummated; or
- the date we consummate a merger, share exchange or consolidation with any other corporation or entity, regardless of whether we are the surviving company, unless our outstanding securities immediately prior to the transaction continue to represent more than 60% of the combined voting power of the outstanding voting securities of the surviving entity immediately after the transaction; or
- the date, when, as a result of a tender offer, exchange offer, proxy contest, merger, share exchange, consolidation, sale of assets or any combination of the foregoing, the directors serving as of the effective date of the change-in-control plan, or elected thereafter with the support of not less than 75% of those directors, cease to constitute at least two-thirds (⅔) of the members of the Board of Directors; or
- the date that our shareholders approve a plan of complete liquidation or winding-up or an agreement for the sale or disposition by us of all or substantially all of our assets; or

- the date of any other event that our Board of Directors determines should constitute a CIC.

The purposes of the CIC Plan and the levels of payment it provides are designed to:

- focus executives on maximizing shareholder value;
- ensure business continuity during a transition and thereby maintain the value of the acquired company;
- allow executives to focus on their jobs by easing termination concerns;
- demonstrate the Company's commitment to its executives;
- reward executives for their role in executing a transition and, if appropriate, align awards with the new company's performance;
- recognize the additional stress, efforts and responsibilities of employees during periods of transition; and
- keep executives in place and provide them with severance only if a CIC transaction is completed.

The Committee has the sole authority and discretion to designate employees and/or positions for participation in the CIC Plan. The Committee has designated certain positions, including all of the named executive officer positions, for participation in the CIC Plan. Participants are not eligible to receive any of the CIC Plan's benefits absent both a CIC of the Company and an involuntary termination of the participant's employment without cause, including voluntary termination for good reason. Good reason termination includes changes in employment circumstances such as:

- a reduction of base salary or incentive targets;
- certain reductions in position or scope of authority;
- a significant change in work location; or
- a breach of provisions of the CIC Plan.

Rather than allowing benefit amounts to be determined at the discretion of the Committee, the CIC Plan has specified multipliers designed to be attractive to the executives and competitive with current market practices. With the assistance of its executive compensation and benefits consultant, the Committee has reviewed the benefits provided under the CIC Plan to ensure that they meet the Company's needs, are reasonable and fall within competitive parameters. The Committee has determined that the current multipliers are needed for the CIC Plan to be effective at meeting the goals described above.

The CIC Plan provides separate tiers of severance benefits based on the position a participant holds within our Company. The continuation of health and welfare benefits coverage and the degree of excise tax gross-up for terminated participants align with the length of time during which they will receive severance benefits.

The following table sets forth the key provisions of the CIC Plan benefits as it relates to our named executive officers:

	Tier I	Tier II
Eligible Positions	Chief Executive Officer, Chief Operating Officer, Presidents and Executive Vice Presidents	Senior Vice Presidents
Cash Severance	300% of base salary and annual incentive[1]	200% of base salary and annual incentive[1]
Health & Welfare Coverage Period	Coverage up to 36 months	Coverage up to 24 months
Gross-ups	Full gross-up of excise tax	Conditional gross-up of excise tax

[1] The cash severance payment will be equal to the sum of the applicable percentage of annual base salary and the greater of the average of the participant's annual incentive award for the three years immediately preceding the participant's employment termination date, or the participant's target annual incentive award for the year the participant's employment with the Company terminates.

Additionally, the following benefits are potentially available to named executive officers upon a CIC.

Benefit	Description
Annual Incentive	100% of target incentive in year of CIC
Restricted Stock Agreements	Restrictions are fully waived on all outstanding grants upon termination
Performance Share Sub-Plan	Outstanding awards vest as of the termination date
Stock Option Agreements	Rights dependent upon whether option has been assumed by successor
Supplemental Senior Executive Retirement Plan	Participant shall be deemed to have met minimum service requirements for benefit purposes, and participant shall be entitled to payment of benefit under the SERP
Deferred Compensation	Entitled to payment of accrued benefits in all accrued nonqualified deferred compensation plans
Split-Dollar Life Insurance Policies[1]	We pay all premiums due under a split-dollar life insurance arrangement under which the terminated participant is the insured for a period not to exceed the applicable period of either 36 (Tier I) or 24 (Tier II) months

[1] Prior to 2003, we sponsored an executive split-dollar life insurance program. The plan provided life insurance coverage approximately equal to three times salary for executive officers. During 2003, we discontinued our executive split-dollar program for all future executives and discontinued our payment of premiums on existing split-dollar policies for senior executives in response to the Internal Revenue Service's final split-dollar regulations and the Sarbanes-Oxley Act of 2002. In 2008 the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. All named executive officers surrendered their policies for cash value. Surrender proceeds were issued in January 2009.

In the event of a change-in-control of the Company, each named executive officer can receive the greater of benefits provided under the CIC Plan or severance benefits provided under his employment agreement, but not both. The tables captioned "Potential Payments Upon Termination," on pages 59 through 68 below show the potential payments each of our named executive officers would receive in the event of a CIC.

The CIC Plan also permits the Board to establish a nonqualified trust to protect the benefits of the impacted participants. This type of trust generally is established to protect nonqualified and/or deferred compensation against various risks such as a CIC or a management change-of-heart. Any such trust the Board establishes will be irrevocable and inaccessible to future or current management, and may be currently funded. To date, no such trust has been funded with respect to any of our named executive officers.

6. EMPLOYMENT AGREEMENTS

Each named executive officer has an employment agreement that documents the Company's relationship with that executive. We provide these agreements to the executives as a means of attracting and retaining them. Each agreement has a term of three years. When an agreement's remaining term diminishes to two years, the agreement automatically adds another year to the term, unless we give 60-days advance notice that we do not want to extend the agreement. If a named executive officer is terminated without cause during the term of the agreement, he is entitled to severance payments equal to his base salary times 2.99, as well as up to 18 months of COBRA reimbursement. A description of each named executive officer's employment agreement is discussed under the "Employment Agreement" section of the "Discussion of Summary Compensation Table and Grants of Plan-Based Awards Table" on page 50 of this Proxy Statement.

The Committee provides employment agreements to the named executive officers because it believes that such agreements are important for the Company to be competitive and retain a cohesive management team. The employment agreements also provide for a defined employment arrangement with the executives and provide various protections for the Company, such as prohibiting competition with the Company, solicitation of the Company's employees and disclosure of confidential information or trade secrets. The Committee believes that the terms of the employment agreements are in line with general industry practice.

7. EXECUTIVE PERQUISITES

We provide certain perquisites and other benefits to our executives. Amounts attributable to perquisites are disclosed in the "All Other Compensation" column of the Summary Compensation Table on page 45.

During 2009, the Committee evaluated the perquisites program to determine whether it was competitive and consistent with the Company's compensation philosophy. As a result of this evaluation, the Committee determined that the current perquisites were appropriate and consistent with market practices. The perquisites available to the named executive officers during 2009 include:

Perquisites for 2009	Description
Personal Travel on Corporate Aircraft and "Business-Related" Spousal Travel[1]	Personal and spousal travel on corporate aircraft is permitted under very limited circumstances.
Financial and Estate Planning	An annual allowance of up to $16,500 for the purpose of purchasing financial and estate planning counseling and services and preparation of personal tax return.
Luncheon and Health Club Dues	Membership in an approved luncheon club and membership in a health club of executive officer's choice.
Executive Physical	Reimbursement of up to $2,500 for an extensive physical at a clinic specializing in executive physicals, every other year.
Internet and Telecom Service[2]	Monthly fees for Internet and telecom access.
Home Security	An installed home security system and payment of monitoring fees.
Accidental Death and Dismemberment Insurance	$500,000 of AD&D insurance for each executive officer.

[1] Personal travel on the Company's aircraft in the event of a family emergency or similar situation is permitted with the approval of the Chief Executive Officer. Executives' spouses may travel on the Company's aircraft to accompany the executives to "business-related" events executives' spouses are requested to attend. For 2009, the named executive officers whose perquisites included spousal travel on corporate aircraft for business purposes were Messrs. Lyash and Yates.

[2] Including home use of Company-owned computer.

The Committee believes that the perquisites we provide to our executives are reasonable, competitive and consistent with our overall executive compensation program in that they help us attract and retain skilled and qualified executives. We believe that these benefits generally allow our executives to work more efficiently and, in the case of the tax and financial planning services, help them to optimize the value received from all of the compensation and benefits programs offered. The costs of these benefits constitute only a small percentage of each named executive officer's total compensation.

8. OTHER BROAD-BASED BENEFITS

The named executive officers receive our general corporate benefits provided to all of our regular, full-time, nonbargaining employees. These broad-based benefits include the following:

- participation in our 401(k) Plan (including a limited Company match of up to 6% of eligible compensation);
- participation in our funded, tax-qualified, noncontributory defined-benefit pension plan, which uses a cash balance formula to accrue benefits; and
- general health and welfare benefits such as medical, dental, vision and life insurance, as well as long-term disability coverage.

9. DEFERRED COMPENSATION

We sponsor the Management Deferred Compensation Plan (the "MDCP"), an unfunded, deferred compensation arrangement. The plan is designed to provide executives with tax deferral options, in addition to those available under the existing qualified plans. An executive may elect to defer, on a pre-tax basis, payment of up to 50% of his or her salary for a minimum of five years or until his or her date of retirement. As a make-up for the 401(k) statutory compensation limits, executives receive deferred compensation credits of 6% of their base salary over the Internal Revenue Code statutory compensation limit on 401(k) retirement plans. The Committee views the matching feature as a restoration benefit designed to restore the matching contribution the executive would have received under the 401(k) retirement plan in the absence of the Internal Revenue Service compensation limits. These Company matching allocations are allocated to an account that will be deemed initially to be invested in shares of a stable value fund within the MDCP. Each executive may reallocate his or her deferred compensation among the other available deemed investment funds that mirror those options available under the 401(k) plan.

Executives can elect to defer up to 100% of their MICP and/or performance share awards. The deferral option is provided as an additional benefit to executive officers to provide flexibility in the receipt of compensation. Historically, all deferred awards were deemed to be invested in performance units, generally equivalent to shares of the Company's common stock and received a 15% discount to the Company's then-current common stock price. Beginning January 1, 2009, the discount feature was eliminated and deferred awards may be allocated among investment options that mirror the Company's 401(k) Plan.

III. 2009 COMPENSATION DECISIONS

Company Performance

The Committee made decisions for the executive officers' compensation following the process described above. The Committee noted that under the leadership of our executive officer management team, the Company reported solid financial and operating results in 2009 despite the challenging economic and regulatory environment. Highlights of the Company's 2009 performance include the following:

- Returned value to shareholders including increasing dividends from $642 million in 2008 to $693 million in 2009; dividend payments increased for the 21st consecutive year;
- Total shareholder return in 2009 was 10.4% as compared to the average 2009 total shareholder return for the Benchmarking Peer Group of 9.66%; the Company's 3-year total shareholder return was -0.53% as compared to the average 3-year total shareholder return for the Benchmarking Peer Group of -5.27%;
- Delivered ongoing earnings of $846 million, or $3.03 per share, compared to $776 million, or $2.96 per share in 2008;
- Received approval from the Florida Public Service Commission ("FPSC") to increase base rates by $132 million; the Committee acknowledges that this increase represents only 26% of the Company's request and believes the result was due to the FPSC's unwillingness to meaningfully raise consumer rates in the particularly challenging Florida economic environment;
- Received final orders from the FPSC for all of PEF's proposed 2010 recovery for fuel, environmental and energy-efficiency costs; and
- Filed with the North Carolina Utilities Commission ("NCUC") a plan to retire by the end of 2017 the remaining 11 North Carolina coal-fired units that do not have flue-gas desulfurization controls (scrubbers) and filed a corresponding plan to build a 600-megawatt (MW) natural gas-fired plant to replace the coal-fired units at our Sutton Plant in conjunction with their retirement in 2014; the Sutton Plant project would represent an estimated investment of approximately $600 million and significantly reduce overall emissions.

Chief Executive Officer Compensation

William D. Johnson

In March 2009, the Committee considered Mr. Johnson's salary against the salaries of the chief executive officers in the Benchmarking Peer Group, the Company's performance, and the difficult external economic and regulatory climate. Based on these factors, the Committee approved a salary of $990,000 for Mr. Johnson representing an increase of 4.2% to his 2008 salary. Mr. Johnson's current target total base compensation is approximately 18% below the 50th percentile of the Benchmarking Peer Group due to his relatively short tenure in the Chief Executive Officer position, and more significantly, the challenging economic and regulatory environment. It is the Committee's intention to increase Mr. Johnson's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group. For 2009, the Committee set Mr. Johnson's MICP target award at 85% of base salary. This target award was the same as the target Mr. Johnson had in 2007 after he assumed his new position, and represents a target award opportunity that is below the 50th percentile of market. The payout of the 2009 MICP award was based on the extent to which Mr. Johnson achieved his performance goals, which were focused on the following general areas of Company success:

- Delivering on fundamentals of safety, operational excellence and customer satisfaction;
- Achieving financial objectives;

- Managing capital projects effectively;
- Executing the energy-efficiency and emerging technology features of the Company's Balanced Solution Strategy;
- Achieving reasonable outcome on PEF's 2010 base rate proceeding filed in March 2009;
- Advocating effectively for achievable, affordable climate and renewable energy policies; and
- Strengthening leadership focus on employee engagement, communication, diversity and inclusion.

In recognition of his accomplishments during 2009, including his leadership in achieving the Company Performance described above, the Committee awarded Mr. Johnson an MICP payout of $950,000, which is equal to 114% of Mr. Johnson's target award. The Committee also considered Mr. Johnson's emphasis on specific leadership behaviors and expectations throughout the year which were communicated to the Company's management team in clear and direct terms. The Committee also noted Mr. Johnson's active leadership in key national industry organizations, including frequent, direct engagement with policymakers and regulators at the federal and state levels.

With respect to his long-term incentive compensation during 2009, Mr. Johnson was granted 27,892 restricted stock units and 55,546 performance shares in accordance with his pre-established targets of 117% and 233%, respectively, of his base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. Additionally, 29,456 shares of the 2007 annual grant vested in 2009 and were paid out at 100% of target. The Committee also issued to Mr. Johnson an ad hoc retention grant of 8,000 restricted stock units to recognize his leadership in the critical position of Chief Executive Officer, outstanding performance against objectives and the manner in which he achieved those objectives. Total year-over-year compensation to Mr. Johnson for 2009, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was relatively flat.

Chief Financial Officer Compensation

Mark F. Mulhern

In March 2009, Mr. Johnson recommended and the Committee approved a base salary of $425,000 for Mr. Mulhern, representing a 10.4% increase to his previous salary of $385,000. The new base salary was set at 20% below the 50th percentile of the Benchmarking Peer Group. Mr. Mulhern's base salary was established at this level due to his relatively short tenure in the Chief Financial Officer position, and more significantly, the challenging economic and regulatory environment. It is the Committee's intention to increase Mr. Mulhern's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group.

For 2009, Mr. Mulhern's MICP target award was set at 55% of his base salary. This target award is the same target Mr. Mulhern had in 2008 after he assumed the Chief Financial Officer position and represents a target award opportunity that is below the 50th percentile of the market. Mr. Mulhern's performance goals for 2009 focused on the following general areas of Company success:

- Achieving financial objectives;
- Developing a pension funding strategy and communicating it effectively to the investment community;
- Achieving reasonable outcome on PEF's rate settlement with respect to 2006-2008 expenditures; and
- Strengthening leadership focus on employee engagement, communication, diversity and inclusion.

In recognition of the achievements he accomplished in 2009 and on Mr. Johnson's recommendation, the Committee awarded Mr. Mulhern an MICP payout of $225,000, which is equal to 99% of Mr. Mulhern's target award. Mr. Mulhern's award was due in part to his leadership in the Company achieving its EPS goal, execution of a funding strategy for the pension plan, and obtaining interim rate relief for PEF.

With respect to his long-term incentive compensation, in 2009, Mr. Mulhern was granted 5,604 restricted stock units and 11,304 performance shares in accordance with his pre-established targets of 58% and 117%, respectively, of base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. Additionally, 7,131 shares of the 2007 annual grant vested in 2009 and were paid out at 100% of target. On Mr. Johnson's recommendation, the Committee also issued to Mr. Mulhern an ad hoc retention grant of 2,500 restricted stock units to recognize his leadership in the critical position of Chief Financial Officer, his outstanding performance against objectives and the manner in which he achieved those objectives. The decrease in year-over-year total compensation to Mr. Mulhern for 2009, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to vesting of the total accumulated SERP benefit that occurred in 2008.

Compensation of Other Named Executive Officers

For 2009, Mr. Johnson recommended and the Committee approved base salaries for Messrs. Lyash and Yates of $453,000 and $448,000, respectively. The base salaries for Messrs. Lyash and Yates represented an increase of approximately 1.80% and 1.82%, respectively, above their 2008 salaries. The new base salaries are set at 9% below the 50th percentile of the market. The modest year-over-year increase to Mr. Lyash's and Mr. Yates' salaries reflects the Committee's and management's recognition of the challenging economic and regulatory environment. It is the Committee's intention to increase Messrs. Lyash's and Yates' salaries over time to a level that is at the 50th percentile of the Benchmarking Peer Group.

For 2009, Mr. Johnson recommended and the Committee approved Ms. Sims' base salary to remain at $370,000. The 2009 base salary is set at 11% above the 50th percentile of the Benchmarking Peer Group due to Ms. Sims' extensive knowledge of fuel and power operations.

Mr. Lyash received standard assistance with relocation expenses in connection with the Company's requirement that he relocate from Florida to North Carolina to assume his current position. Mr. Lyash also received assistance with the sale of his Florida home. For more information, see note 16 to the "Summary Compensation Table" on page 45.

On Mr. Johnson's recommendation, the Committee awarded Messrs. Lyash and Yates and Ms. Sims 2009 MICP awards as described in the table below.

Named Executive Officer	2009 MICP Award	Percent of Target	Explanation of Award
Jeffrey J. Lyash	$235,000	95%	Mr. Lyash played a significant role in mitigating a substantial reduction in PEF's retail revenue through a combination of O&M reductions, wholesale contracts and rate mitigation resulting in PEF's attaining its earnings goals; completion of the Bartow Plant repowering that is reflected in rates; and implementation of project oversight process.
Lloyd M. Yates	$235,000	96%	Mr. Yates played a significant role in the Company's achievement of its EPS goal and PEC's achievement of its capital spending budget goal; led development of fleet modernization strategy to replace coal-fired plants with natural gas-fired plants; execution of wholesale expansion and renewal contracts on favorable terms; and development of effective relationships in the regulatory and legislative arenas resulting in passage of significant legislation in North Carolina.
Paula J. Sims	$160,000	96%	Ms. Sims played a significant role in the Power Operation Group's achievement of its O&M and capital spending goals; led the Continuous Business Excellence effort to obtain sustainable 3-5% productivity gains; implementation of a strategy to reduce emissions by replacing coal-fired plants with natural gas-fired plants; and increased the focus on safety by reducing our OSHA injury rate.

With respect to long-term compensation, in 2009 each of the other named executive officers received annual grants of restricted stock units and performance shares in accordance with their pre-established targets. The table below describes those grants, the transitional performance share grants that the Committee issued in 2007, and the ad hoc restricted stock unit grants.

Named Executive Officer	Restricted Stock Units Vesting in 1/3 Increments in 2010, 2011 and 2012	Transitional Performance Shares Vesting 2009	Performance Shares Vesting 2012	Ad Hoc Restricted Stock Units Vesting 2012
Jeffrey J. Lyash	6,477	9,535	13,065	2,000
Lloyd M. Yates	6,404	9,535	12,918	2,000
Paula J. Sims	4,642	7,131	9,285	2,000

The increase in total compensation to Mr. Lyash, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to the increase in his equity grants value and the receipt of relocation expenses and assistance with the sale of his Florida home.

The decrease in year-over-year total compensation to Mr. Yates, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to vesting of the total accumulated SERP benefit that occurred in 2008.

The significant increase in year-over-year total compensation to Ms. Sims, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to her vesting in the SERP in 2009.

IV. COMPENSATION COMMITTEE REPORT

The Committee has reviewed and discussed this CD&A with management as required by Item 402(b) of Regulation S-K. Based on such review and discussions, the Committee recommended to the Company's Board of Directors that the CD&A be included in this Proxy Statement.

Organization and Compensation Committee

E. Marie McKee, Chair
John D. Baker II
Harris E. DeLoach, Jr.
James B. Hyler, Jr.
Robert W. Jones
John H. Mullin, III

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Compensation Committee Report shall not be deemed soliciting material, shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

SUMMARY COMPENSATION TABLE FOR 2009

The following Summary Compensation Table discloses the compensation during 2009 of our Chief Executive Officer, Chief Financial Officer, and the other three most highly paid executive officers who were serving at the end of 2009. Additionally, column (h) is dependent upon actuarial assumptions for determining the amounts included. A change in these actuarial assumptions would impact the values shown in this column. Where appropriate, we have indicated the major assumptions in the footnotes to column (h).

Name and Principal Position (a)	Year (b)	Salary[1] ($) (c)	Bonus ($) (d)	Stock Awards[2] ($) (e)	Option Awards[3] ($) (f)	Non-Equity Incentive Plan Compensation[4] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[5] ($) (h)	All Other Compensation[6] ($) (i)	Total[2] ($) (j)
William D. Johnson,	2009	$979,231	N/A	$3,090,605[8]	$0	$950,000	$1,144,448[9]	$289,726[10]	$6,454,010
Chairman, President and	2008	950,000		2,911,701	0	929,000	1,091,256	304,571	6,186,528
Chief Executive Officer[7]	2007	807,539		5,231,023	0	863,500	946,938	299,445	8,148,445
Mark F. Mulhern,	2009	$414,231	N/A	$655,990[11]	$0	$225,000	$369,822[12]	$102,137[13]	$1,767,180
Senior Vice President and	2008	355,385		433,473	0	200,000	820,419	141,354	1,950,631
Chief Financial Officer	2007	308,792		1,620,321	0	190,000	34,205	116,014	2,269,332
Jeffrey J. Lyash, Executive	2009	$450,846	N/A	$728,120[14]	$0	$235,000	$244,369[15]	$292,061[16]	$1,950,396
Vice President – Corporate	2008	432,885		612,952	0	225,000	323,904	140,812	1,735,553
Development (formerly President and Chief Executive Officer, PEF)	2007	386,154		2,146,232	0	265,000	272,656	125,548	3,195,590
Lloyd M. Yates,	2009	$445,846	N/A	$720,683[17]	$0	$235,000	$308,815[18]	$119,432[19]	$1,829,776
President and Chief	2008	429,231		612,952	0	210,000	777,983	155,042	2,185,208
Executive Officer, PEC	2007	374,039		2,146,232	0	265,000	26,730	127,981	2,939,982
Paula J. Sims,	2009	$370,000	N/A	$538,333[20]	$0	$160,000	$707,802[21]	$97,505[22]	$1,873,640
Senior Vice President –	2008	364,615		459,724	0	140,000	25,728	92,743	1,082,810
Power Operations	2007	324,177		1,620,321	0	170,000	21,930	108,233	2,244,661

[1] Consists of base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if any, under the Management Deferred Compensation Plan. See "Deferred Compensation" discussion in Part II of the CD&A. Salary adjustments, if deemed appropriate, generally occur in March of each year.

[2] Includes the fair value of stock awards as of the grant date computed in accordance with FASB ASC Topic 718. Assumptions made in the valuation of material stock awards are discussed in Note 9.B. to our consolidated financial statements for the year ended December 31, 2009. The values reflected for 2008 and 2007 in columns (e) and (j) are different than previously disclosed because these values represent the fair value of stock awards as of the grant date rather than the expense related to equity awards for financial statement reporting purposes in accordance with SFAS No. 123(R).

[3] We ceased granting stock options in 2004. No additional expense remains with respect to our stock option program.

[4] Includes the awards given under the Management Incentive Compensation Plan (MICP) for 2007, 2008 and 2009 performance.

[5] Includes the change in present value of the accrued benefit under Progress Energy's Pension Plan, SERP, and/or Restoration Plan where applicable. In addition, it includes the above market earnings on deferred compensation under the Deferred Compensation Plan for Key Management Employees. The current incremental present values were determined using actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates of 6.25%, 6.30%, and 6.10% for calculating the accrued benefit under the SERP for 2007, 2008, and 2009, respectively. FAS discount rates of 5.95%, 6.25%, and 5.45% were used for calculating the accrued benefits under the Restoration Retirement Plan for 2007, 2008, and 2009, respectively. FAS discount rates of 6.15%, 6.30%, and 5.95% were used for calculating the accrued benefits under the Pension Plan for 2007, 2008, and 2009, respectively. The 1996-1999 Deferred Compensation Plan for Key Management Employees provided a fixed rate of return of 10.0% on deferred amounts,

which was 2.7% above the market interest rate of 7.3% at the time the plan was frozen in 1996. The Deferred Compensation Plan for Key Management Employees was discontinued in 2000 and replaced with the Management Deferred Compensation Plan, which does not have a guaranteed rate of return. Named executive officers who were participants in the 1996-1999 Deferred Compensation Plan for Key Management Employees continue to receive plan benefits with respect to amounts deferred prior to its discontinuance in 2000. The above market earnings under the Deferred Compensation Plan for Key Management Employees are included in this column for Mr. Johnson.

[6] Includes the following items: Company match contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; dividends paid under provisions of the Restricted Stock Award/Unit Plans and Management Deferred Compensation Plans; perquisites; and tax gross-ups related primarily to imputed income.

[7] Mr. Johnson did not receive additional compensation for his service on the Board of Directors.

[8] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $1,213,150; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $1,877,455. The maximum potential for the performance shares granted to Mr. Johnson in 2009 is $3,754,910 (200%), based on the March 17, 2009 closing stock price of $33.80.

[9] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $65,737; the SERP: $1,068,674; and above market earnings on compensation deferred under the Deferred Compensation Plan for Key Management Employees of $10,037. Mr. Johnson's change in his year-over-year SERP benefit was relatively flat.

[10] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $43,582 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $195,485 in Restricted Stock/Unit Dividends; (iv) $11,970 in tax gross-ups related to imputed income; and (v) $23,989 in perquisites consisting of the following: financial/estate/tax planning, $5,000; Internet and telecom access, $3,724; health club dues, $2,407; home security, $4,255; and spousal travel, $6,370. Other perquisites include luncheon club membership, executive physical and AD&D insurance.

[11] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $273,915; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $382,075. The maximum potential for the performance shares granted to Mr. Mulhern in 2009 is $764,150 (200%), based on the March 17, 2009 closing stock price of $33.80.

[12] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $46,636; and the SERP: $323,186. Mr. Mulhern's change in SERP decreased in 2009 primarily due to vesting of the total accumulated benefit that occurred in 2008.

[13] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $9,682 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $5,276 in tax gross-ups related to imputed income; and (iv) $72,479 in Restricted Stock/Unit Dividends. The total value of the perquisites and personal benefits received by Mr. Mulhern was less than $10,000. Thus, these amounts are excluded from column (i).

[14] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $286,523; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $441,597. The maximum potential for the performance shares granted to Mr. Lyash in 2009 is $883,194 (200%), based on the March 17, 2009 closing stock price of $33.80.

[15] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $48,250; and the SERP: $196,119. Mr. Lyash's change in SERP decreased in 2009 primarily due to a lower FAS discount rate.

[16] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $12,256 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $70,378 in Restricted Stock/Unit Dividends; (iv) $1,445 in tax gross-ups related to imputed income; and (v) $17,708 in perquisites including spousal use of Company aircraft, $14,669. Other perquisites include luncheon club membership, spousal

travel, home security, and Internet and telecom access. During 2009, the Company required Mr. Lyash to relocate from Florida to North Carolina in connection with his becoming the Company's Executive Vice President - Corporate Development. Mr. Lyash received standard Company relocation benefits totaling $53,005 that included travel expenses, the equivalent of one month's salary, temporary housing, shipment of household goods, and closing costs in connection with his purchase of a home in North Carolina. Mr. Lyash also received assistance with the sale of his home in Florida where the Company previously required Mr. Lyash to relocate in connection with his former role as President and Chief Executive Officer of Progress Florida, Inc. The Company purchased his Florida home at a price equal to the average of two independent appraisals after he was unable to sell the home within a 60-day marketing period. The Company agreed that if the purchase price of Mr. Lyash's Florida home, as determined by the average of the two independent appraisals, resulted in a loss on the sale of his prior home, the Company would pay Mr. Lyash the difference between the price he paid for the Florida home (excluding the cost of improvements made subsequent to such purchase) and the purchase price paid by the Company based on the independent appraisals. Because of the precipitous decline in the Florida housing market since Mr. Lyash's purchase of his Florida home, the agreed purchase price was significantly below Mr. Lyash's purchase price. SEC rules require that we include as fiscal year 2009 compensation this difference, which was $80,000, along with other transaction costs. In light of the fact that the relocation was required by the Company and because this make-whole amount paid to Mr. Lyash will be treated as income to him, we agreed to provide Mr. Lyash with a tax gross-up on amounts from this transaction that are considered taxable income. The tax gross-up was $42,569. In approving Mr. Lyash's relocation expenses, including the reimbursement of the loss incurred on his Florida home, the Committee required Mr. Lyash to agree to reimburse the Company for the relocation assistance in the event he voluntarily leaves the Company within three years of relocating to North Carolina.

[17] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $284,055; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $436,628. The maximum potential for the performance shares granted to Mr. Yates in 2009 is $873,257 (200%), based on the March 17, 2009 closing stock price of $33.80.

[18] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $33,106; and the SERP: $275,709. Mr. Yates' change in SERP decreased in 2009 primarily due to vesting of the total accumulated benefit that occurred in 2008.

[19] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $11,956 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $70,986 in Restricted Stock/Unit Dividends; (iv) $4,026 in tax gross-ups related to imputed income; and (v) $17,764 in perquisites including financial/estate/tax planning, $10,000, and spousal use of Company aircraft, $4,920. Other perquisites include luncheon club membership, health club dues, home security, Internet and telecom access, executive physical and AD&D insurance.

[20] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $224,500; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $313,833. The maximum potential for the performance shares granted to Ms. Sims in 2009 is $627,666 (200%), based on the March 17, 2009 closing stock price of $33.80.

[21] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $30,117; and the SERP: $703,105. Ms. Sims became vested in the SERP on June 1, 2009 which attributed to her increase for the year. Ms. Sims' accumulated Restoration Plan benefit of $25,420 was forfeited upon her vesting in the SERP.

[22] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $7,500 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $47,759 in Restricted Stock/Unit Dividends; (iv) $15,188 in tax gross-ups related to imputed income; and (v) $12,358 in stock purchase discounts for annual incentive deferrals pursuant to the MICP. The total value of the perquisites and personal benefits received by Ms. Sims was less than $10,000. Thus, these amounts are excluded from column (i).

GRANTS OF PLAN-BASED AWARDS

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units[3] (#) (i)	Grant Date Fair Value of Stock and Option Awards[4] ($) (j)
William D. Johnson, Chairman, President and Chief Executive Officer	MICP 3/5/10	$416,173	$832,346	$1,664,692					
	Restricted Stock Units 3/17/09							35,892	$1,213,150
	PSSP 3/17/09				27,773	55,546	111,092		$1,877,455
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	MICP 3/5/10	$113,914	$227,827	$455,654					
	Restricted Stock Units 3/17/09							8,104	$273,915
	PSSP 3/17/09				5,652	11,304	22,608		$382,075
Jeffrey J. Lyash, Executive Vice President - Corporate Development (formerly President and Chief Executive Officer, PEF)	MICP 3/5/10	$123,983	$247,965	$495,930					
	Restricted Stock Units 3/17/09							8,477	$286,523
	PSSP 3/17/09				6,533	13,065	26,130		$441,597
Lloyd M. Yates, President and Chief Executive Officer, PEC	MICP 3/5/10	$122,608	$245,215	$490,430					
	Restricted Stock Units 3/17/09							8,404	$284,055
	PSSP 3/17/09				6,459	12,918	25,836		$436,628
Paula J. Sims, Senior Vice President – Power Operations	MICP 3/5/10	$83,250	$166,500	$333,000					
	Restricted Stock Units 3/17/09							6,642	$224,500
	PSSP 3/17/09				4,643	9,285	18,570		$313,833

[1] The Management Incentive Compensation Plan is considered a non-equity incentive compensation plan. Award amounts are shown at threshold, target, and maximum levels. The target award is calculated using the 2009 eligible earnings times the executive's target percentage. See target percentage in table on page 30 of the CD&A. Threshold is calculated at 50% of target and maximum is calculated at 200% of target. Actual award amounts paid are reflected in the Summary of Compensation Table under the "Non-Equity Incentive Plan Compensation" column.

[2] Reflects the potential payouts in shares of the 2009 PSSP grants. The grant size was calculated by multiplying the executive's salary as of January 1, 2009, times his 2009 PSSP target and dividing by the December 31, 2008, closing stock price of $39.85. The Threshold column reflects the minimum payment level under our PSSP, which is 50% of the target amount shown in the Target column. The amount shown in the maximum column is 200% of the target amount.

[3] Reflects the number of restricted stock units granted during 2009 under the 2007 Equity Incentive Plan. The number of shares granted was determined by multiplying the executive's salary as of January 1, 2009, times his 2009 restricted stock target and dividing by the December 31, 2008, closing stock price of $39.85.

[4] Reflects the grant date fair value of the award based on the following assumptions: Market value of restricted stock granted on March 17, 2009, based on closing price of $33.80 per share, times the shares granted in column (i). Market value of PSSP granted on March 17, 2009, based on closing stock price on March 17, 2009, of $33.80 times target number of shares in column (g). The 2009 PSSP grant payout is expected to be 100% of target.

DISCUSSION OF SUMMARY COMPENSATION TABLE AND GRANTS OF PLAN-BASED AWARDS TABLE

EMPLOYMENT AGREEMENTS

Messrs. Johnson, Mulhern, Lyash and Yates and Ms. Sims entered into employment agreements with the Company or one of its subsidiaries, referred to collectively in this section as the "Company." Each of these agreements has an effective date of May 8, 2007. The employment agreements replaced the previous employment agreements in effect for each of these officers.

The employment agreements provide for base salary, annual incentives, perquisites and participation in the various executive compensation plans offered to our senior executives. The agreements expired on December 31, 2009. Thereafter, each agreement will be automatically extended by an additional year on January 1 of each year. We may elect not to extend an executive officer's agreement and must notify the officer of such an election at least 60 days prior to the automatic extension date. Each employment agreement contains restrictive covenants imposing non-competition obligations, restricting solicitation of employees and protecting our confidential information and trade secrets for specified periods if the applicable officer is terminated without cause or otherwise becomes eligible for the benefits under the agreement.

Except for the application of previously granted years of service credit to our post-employment health and welfare plans as discussed below, the employment agreements do not affect the compensation, benefits or incentive targets payable to the applicable officers.

With respect to Mr. Johnson, the Employment Agreement specifies that the years of service credit we previously granted to him for purposes of determining eligibility and benefits in the SERP will also be applicable for purposes of determining eligibility and benefits in our post-employment health and welfare benefit plans. Mr. Johnson was awarded seven years of deemed service toward the benefits and vesting requirements of the SERP. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0. Three of those years also were deemed to have been in service on the Senior Management Committee for purposes of SERP eligibility.

Each Employment Agreement provides that if the applicable officer is terminated without cause or is constructively terminated (as defined in Paragraph 8(a)(i) of the agreement), then the officer will receive (i) severance equal to 2.99 times the officer's then-current base salary and (ii) reimbursement for the costs of continued coverage under certain of our health and welfare benefit plans for a period of up to 18 months.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards[1]					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)[2]	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)[3]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[4]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[4]
William D. Johnson, Chairman, President and Chief Executive Officer	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	82,135[5]	$3,368,356	152,673[6]	$6,261,120
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	0 0 7,000	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	26,776[7]	$1,098,084	29,966[8]	$1,228,906
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	29,232[9]	$1,198,804	38,528[10]	$1,580,033
Lloyd M. Yates, President and Chief Executive Officer, PEC	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	29,159[11]	$1,195,811	38,373[12]	$1,573,677
Paula J. Sims, Senior Vice President – Power Operations	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	20,617[13]	$845,503	28,305[14]	$1,160,778

[1] All outstanding stock options were vested as of December 31, 2006. The Company ceased granting stock options in 2004.

[2] Consists of outstanding restricted stock grants and restricted stock units.

[3] Market value at December 31, 2009, was based on a December 31, 2009, closing price of $41.01 per share.

[4] The 2006 and 2007 2-year transitional grants vested on January 1, 2009; the 2007 grant vests on January 1, 2010; the 2008 grant vests on January 1, 2011; and the 2009 grant vests on January 1, 2012. Performance share value for the 2007 annual grant is expected to be at 125% of target while the 2008 annual grant and 2009 annual grant were expected to be 100% of target. The value in Column (j) is derived by multiplying the shares (rounded to the nearest whole share) times the December 31, 2009 closing stock price ($41.01). The difference between the calculated value and the noted value is attributable to fractional shares. See further discussion under "Performance Shares" in Part II of the CD&A.

[5] Restricted stock grants vest based on the following schedule: 5,533 shares on March 14, 2010; 5,067 shares on March 15, 2010; and 5,534 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 9,297 units on March 17, 2010; 9,297 units on March 17, 2011; 17,298 units on March 17, 2012; 7,650 units on March 18, 2010; 4,936 units on March 20, 2010; 7,651 units on March 18, 2011; 4,936 units on March 20, 2011; and 4,936 units on March 20, 2012.

[6] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 43,280 – 2007 annual grant; (ii) 51,018 – 2008 annual grant; and (iii) 58,375 – 2009 annual grant.

[7] Restricted stock grants vest based on the following schedule: 1,167 shares on March 14, 2010; 3,500 shares on March 21, 2010; and 1,167 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 1,868 units on March 17, 2010; 1,868 on March 17, 2011; 4,368 on March 17, 2012; 1,136 units on March 18, 2010; 8,189 units on March 20, 2010; 1,136 units on March 18, 2011; 1,189 units on March 20, 2011; and 1,188 units on March 20, 2012.

[8] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 10,479 – 2007 annual grant; (ii) 7,607 – 2008 annual grant; and (iii) 11,880 – 2009 annual grant.

[9] Restricted stock grants vest based on the following schedule: 1,367 shares on March 14, 2010; 1,100 shares on March 15, 2010; and 1,367 on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 2,159 units on March 17, 2010; 1,597 on March 18, 2010; 10,576 units on March 20, 2010; 2,159 units on March 17, 2011; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; 4,159 units on March 17, 2012; and 1,575 units on March 20, 2012.

[10] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 14,010 – 2007 annual grant; (ii) 10,787 – 2008 annual grant; and (iii) 13,731 – 2009 annual grant.

[11] Restricted stock grants vest based on the following schedule: 1,367 shares on March 14, 2010; 1,100 shares on March 15, 2010; and 1,367 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 2,134 on March 17, 2010; 1,597 on March 18, 2010; 10,576 units on March 20, 2010; 2,135 on March 17, 2011; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; 4,135 on March 17, 2012; and 1,575 units on March 20, 2012.

[12] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 14,010 – 2007 annual grant; (ii) 10,787 – 2008 annual grant; and (iii) 13,576 – 2009 annual grant.

[13] Restricted stock grants vest based on the following schedule: 1,000 shares on April 1, 2011. Restricted stock units grants vest based on the following schedule: 1,547 units on March 17, 2010; 1,204 units on March 18, 2010; 8,189 units on March 20, 2010; 1,547 units on March 17, 2011; 1,205 units on March 18, 2011; 1,189 units on March 20, 2011; 3,548 units on March 17, 2011; and 1,188 units on March 20, 2012.

[14] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 10,479 – 2007 annual grant; (ii) 8,068 – 2008 annual grant; and (iii) 9,758 – 2009 annual grant.

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting[1] (#) (d)	Value Realized on Vesting[1] ($) (e)
William D. Johnson, Chairman, President and Chief Executive Officer	—	—	55,597[2]	$2,049,258
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	—	—	18,077[3]	$656,906
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	—	—	15,727[4]	$589,337
Lloyd M. Yates, President and Chief Executive Officer, PEC	—	—	16,927[5]	$630,131
Paula J. Sims, Senior Vice President – Power Operations	—	—	9,180[6]	$358,539

[1] Reflects the number of restricted stock shares, restricted stock units, and performance shares that vested in 2009. Restricted stock units vested for named executive officers on March 18 at $33.80 per share, and performance shares vested on January 1, 2009 for the 2006 and 2007 2-year transitional grants at $39.85 per share. Restricted stock shares vested on the following days: (i) March 7 at $33.02 per share; (ii) March 14, 15, and 16 at $31.85 per share; and (iii) April 28 at $33.79 per share. The value realized is the sum of the vested shares for each vesting date times the vesting price.

[2] Includes 15,000 restricted stock awards consisting of the following: 5,533 on March 14; 5,067 on March 15; and 4,400 on March 16. Performance shares totaled 32,947. Restricted stock units totaled 7,650.

[3] Includes 8,966 restricted stock awards consisting of the following: 1,166 on March 14; and 7,800 on April 28. Performance shares totaled 7,976. Restricted stock units totaled 1,135.

[4] Includes 3,466 restricted stock awards consisting of the following: 1,366 on March 14; 1,100 on March 15; and 1,000 on March 16. Performance shares totaled 10,665. Restricted stock units totaled 1,596.

[5] Includes 4,666 restricted stock awards consisting of the following: 2,200 on March 7; 1,366 on March 14; and 1,100 on March 15. Performance shares totaled 10,665. Restricted stock units totaled 1,596.

[6] Performance shares totaled 7,976. Restricted stock units totaled 1,204. Ms. Sims did not have any restricted stock awards that vested during 2009.

PENSION BENEFITS TABLE

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit[1] ($) (d)	Payments During Last Fiscal Year ($) (e)
William D. Johnson, Chairman, President and Chief Executive Officer	Progress Energy Pension Plan	17.3	$448,578	$0
	Supplemental Senior Executive Retirement Plan	24.3[2]	$7,282,483[3]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	Progress Energy Pension Plan	13.8	$269,399	$0
	Supplemental Senior Executive Retirement Plan	13.8	$1,144,767[4]	$0
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	Progress Energy Pension Plan	16.6	$274,417	$0
	Supplemental Senior Executive Retirement Plan	16.6	$1,419,208[5]	$0
Lloyd M. Yates, President and Chief Executive Officer, PEC	Progress Energy Pension Plan	11.1	$157,608	$0
	Supplemental Senior Executive Retirement Plan	11.1	$1,065,706[6]	$0
Paula J. Sims, Senior Vice President – Power Operations	Progress Energy Pension Plan	10.6	$131,941	$0
	Restoration Retirement Plan	—	($25,420)[7]	$0
	Supplemental Senior Executive Retirement Plan	10.6	$703,105[8]	$0

[1] Actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates as of December 31, 2009, for computation of accumulated benefit under the Supplemental Senior Executive Retirement Plan and the Progress Energy Pension Plan was 6.10%. Additional details on the formulas for computing benefits under the Supplemental Senior Executive Retirement Plan and Progress Energy Pension Plan can be found under the headings "Supplemental Senior Executive Retirement Plan" and "Other Broad-Based Benefits," respectively, in the CD&A.

[2] Includes seven years of deemed service. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0.

[3] Based on an estimated annual benefit payable at age 65 of $1,043,010.

[4] Based on an estimated annual benefit payable at age 65 of $233,894.

[5] Based on estimated annual benefit payable at age 65 of $326,421.

[6] Based on estimated annual benefit payable at age 65 of $231,022.

[7] Ms. Sims' Restoration Retirement Plan benefits were forfeited upon her vesting in the Senior Supplemental Retirement Plan on June 1, 2009.

[8] Based on estimated annual benefit payable at age 65 of $161,716.

NONQUALIFIED DEFERRED COMPENSATION

The table below shows the nonqualified deferred compensation for each of the named executive officers. Information regarding details of the deferred compensation plans currently in effect can be found under the heading "Deferred Compensation" in the CD&A on page 39 of this Proxy Statement. In addition, the Deferred Compensation Plan for Key Management Employees is discussed in footnote 5 to the "Summary Compensation Table."

Name and Position (a)	Executive Contributions in Last FY[1] ($) (b)	Registrant Contributions in Last FY[2] ($) (c)	Aggregate Earnings in Last FY[3] ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE[4] ($) (f)
William D. Johnson, Chairman, President and Chief Executive Officer	$0	$43,582	$76,353[5]	$0	$736,071[6]
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$20,712	$9,682	$30,580	($32,861)[7]	$325,876[8]
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	$0	$12,256	$31,303	$0	$135,173[9]
Lloyd M. Yates, President and Chief Executive Officer, PEC	$0	$11,956	$60,701	$0	$499,804[10]
Paula J. Sims, Senior Vice President – Power Operations	$107,000	$19,858	$44,241	($14,115)[11]	$444,049[12]

[1] Reflects salary deferred under the Management Deferred Compensation Plan, which is reported as "Salary" in the Summary Compensation Table. For 2009, named executive officers deferred the following percentages of their base salary: (i) Mulhern – 5%; and (ii) Sims – 10%. In addition, Ms. Sims deferred 50% of her 2009 Management Incentive Compensation Plan (MICP) award.

[2] Reflects registrant contributions under the Management Deferred Compensation Plan, which is reported as "All Other Compensation" in the Summary Compensation Table.

[3] Includes aggregate earnings in the last fiscal year under the following nonqualified plans: Management Incentive Compensation Plan, Management Deferred Compensation Plan, Performance Share Sub-Plan, and Deferred Compensation Plan for Key Management Employees.

[4] Includes December 31, 2009 balances under the following deferred compensation plans: Management Incentive Compensation Plan, Performance Share Sub-Plan, Management Deferred Compensation Plan, and Deferred Compensation Plan for Key Management Employees.

[5] Includes above market earnings of $10,037 under the Deferred Compensation Plan for Key Management Employees, which is reported as "Change in Pension Value and Nonqualified Deferred Compensation Earnings" in the Summary Compensation Table.

[6] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $413,100; Management Incentive Compensation Plan: $69,090; and Deferred Compensation Plan for Key Management Employees: $253,881.

[7] Mr. Mulhern received distributions from his Management Incentive Deferred Compensation Plan: $23,077; Management Deferred Compensation Plan: $0; and Performance Share Sub-Plan: $9,784.

[8] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $71,311; Management Incentive Deferred Compensation Plan: $155,570; and Performance Share Sub-Plan: $98,995.

[9] Includes balance under the Management Deferred Compensation Plan: $135,173.

[10] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $134,519; Management Incentive Deferred Compensation Plan: $107,892; and Performance Share Sub-Plan: $257,393.

[11] Ms. Sims received a distribution from her Management Incentive Deferred Compensation Plan: $14,115.

[12] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $296,625; Management Incentive Compensation Plan: $86,401; and Performance Share Sub-Plan: $61,023.

CASH COMPENSATION AND VALUE OF VESTING EQUITY TABLE

The following table shows the actual cash compensation and value of vesting equity received in 2009 by the named executive officers. The Committee believes that this table is important in order to distinguish between the actual cash and vested value received by each named executive officer as opposed to the compensation expense accruals and grant date fair value of equity awards as shown in the Summary Compensation Table.

Name and Position	Base Salary (a)[1]	Annual Incentive (paid in 2009) (b)[2]	Deferred Compensation under MDCP and MICP (c)[3]	Restricted Stock / Units Vesting (d)[4]	Performance Shares Vesting (e)[5]	Restricted Stock / Unit Dividends (f)[6]	Stock Options Vesting (g)[7]	Perquisite (h)[8]	Tax Gross-ups (i)[9]	Total
William D. Johnson, Chairman, Chief Executive Officer and President	$979,231	$929,000	$0	$736,320	$1,163,688	$195,485	$0	$23,989	$11,970	$4,039,683
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$414,231	$200,000	$20,712	$339,062	$281,712	$72,479	$0	$2,093	$5,276	$1,314,853
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	$450,846	$225,000	$0	$164,337	$376,688	$70,378	$0	$5,621	$44,015	$1,336,885
Lloyd M. Yates, President and Chief Executive Officer, PEC	$445,846	$210,000	$0	$205,131	$376,688	$70,986	$0	$13,726	$4,026	$1,326,403
Paula J. Sims, Senior Vice President – Power Operations	$370,000	$140,000	$107,000	$40,695	$281,712	$47,759	$0	$9,587	$15,188	$904,941

[1] Consists of the total 2009 base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if applicable, under the Management Deferred Compensation Plan (MDCP) shown in column (c).

[2] Awards given under the Management Incentive Compensation Plan (MICP) attributable to Plan Year 2008 and paid in 2009.

[3] Consists of amounts deferred under the MDCP and the MICP. These deferral amounts are part of Base Pay and/or Annual Incentive and therefore are not included in the Total column.

[4] Reflects the value of restricted stock and restricted stock units vesting in 2009. The value of the restricted stock was calculated using the opening stock price for Progress Energy Common Stock three days prior to the day vesting occurred. The value of the restricted stock units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when vesting occurred.

[5] Reflects the value of performance shares vesting on January 1, 2009. The value of the 2007 2-year transitional performance share units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when distribution occurred.

[6] Reflects dividends and dividend equivalents paid as the result of outstanding restricted stock or restricted stock units held in Company Plan accounts.

[7] Reflects the value of any stock options vesting in 2009. Since we ceased granting stock options under our Incentive Plans in 2004, all outstanding options had fully vested in 2009.

[8] Reflects the value of all perquisites provided during 2009. For a complete listing of the perquisites, see the "Executive Perquisites" section of the "Elements of Compensation" discussion of the CD&A on page 38 of this Proxy Statement. Perquisite details for each named executive officer are discussed in the Summary Compensation Table footnotes.

[9] Reflects the value of tax gross-up related to miscellaneous income items (Supplemental Senior Executive Retirement Plan (SERP) or Restoration and MDCP 401(k) make-up) provided during 2009. In addition, Mr. Lyash received an additional $42,569 in tax gross-up from the loss on the sale of his home as disclosed in the Summary Compensation Table footnotes.

POTENTIAL PAYMENTS UPON TERMINATION
William D. Johnson, Chairman, Chief Executive Officer, and President

	Voluntary Termination ($)	Early Retirement[1] ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$990,000[2]	$0	$0	$0	$2,960,100	$0	$5,657,500	$0
Annual Incentive[3]	$0	$950,000	$0	$0	$0	$841,500	$950,000
Long-term Incentives							
Performance Shares (PSSP)[4]							
2007 (performance period)	$0	$1,774,913	$0	$0	$0	$1,774,913	$1,774,913
2008 (performance period)	$0	$1,394,832	$0	$0	$0	$2,092,248	$1,394,832
2009 (performance period)	$0	$797,986	$0	$0	$0	$2,393,959	$797,986
Restricted Stock Units[5]							
2007 – 2010 (grant date vesting)	$0	$185,557	$0	$0	$0	$202,425	$202,425
2007 – 2011 (grant date vesting)	$0	$139,167	$0	$0	$0	$202,425	$202,425
2007 – 2012 (grant date vesting)	$0	$111,334	$0	$0	$0	$202,425	$202,425
2008 – 2010 (grant date vesting)	$0	$274,511	$0	$0	$0	$313,727	$313,727
2008 – 2011 (grant date vesting)	$0	$183,031	$0	$0	$0	$313,768	$313,768
2009 – 2010 (grant date vesting)	$0	$285,952	$0	$0	$0	$381,270	$0
2009 – 2011 (grant date vesting)	$0	$142,976	$0	$0	$0	$381,270	$0
2009 – 2012 (grant date vesting)	$0	$177,348	$0	$0	$0	$709,391	$0
Restricted Stock[6]							
Unvested and Accelerated	$0	$661,655	$0	$0	$0	$661,655	$661,655
Benefits and Perquisites							
Incremental Nonqualified Pension[7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[8]	$736,071	$736,071	$0	$736,071	$736,071	$736,071	$736,071
Post-retirement Health Care[9]	$0	$0	$0	$23,022	$0	$45,140	$0
Executive AD&D Proceeds[10]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[11]	$0	$0	$0	$0	$0	$5,097,620	$0
TOTAL	**$736,071**	**$7,815,333**	**$0**	**$3,719,193**	**$736,071**	**$22,007,307**	**$8,050,227**

[1] Mr. Johnson became eligible for early retirement at age 55 in January 2009. Therefore, under the voluntary termination and involuntary not for cause termination scenarios, Mr. Johnson would be treated as having met the early retirement criteria under the Equity Incentive Plan and would be paid out under the early retirement provisions of that plan.

[2] There is no provision for payment of salary under voluntary termination, early retirement, for cause termination, death or disability. Mr. Johnson is not eligible for normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Johnson's employment agreement requires a severance equal to 2.99 times his then current base salary ($990,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus average MICP award for the three years prior times three (($990,000 + $895,833) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Johnson would receive 60% of base salary during the period of his disability.

[3] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Johnson would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 85% times $990,000. In the event of early retirement, death or disability, Mr. Johnson would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Johnson's MICP award was $950,000.

[4] Unvested performance shares would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. Mr. Johnson is not eligible for normal retirement. In the event of early retirement, Mr. Johnson would receive 43,280 performance shares from the 2007 grant; 34,012 performance shares from the 2008 grant; and 18,458 performance shares from the 2009 grant. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[5] Unvested restricted stock units (RSU) would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. In the event of early retirement, Mr. Johnson would receive a pro-rata percentage of the unvested units, based upon the number of full months elapsed between the grant date and the date of early retirement. Mr. Johnson would vest the following on a pro-rata basis: 10,633 restricted stock units granted on March 20, 2007; 11,157 restricted stock units granted on March 18, 2008; and 14,784 units granted on March 17, 2009. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Johnson would immediately vest 14,808 restricted stock units granted on March 20, 2007; 15,301 restricted stock units granted on March 18, 2008; and would forfeit 35,892 restricted stock units granted on March 17, 2009.

[6] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. In the event of early retirement, all 16,134 outstanding restricted stock shares may vest at the Committee's discretion. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Johnson's restricted stock grant dates are beyond the one-year threshold; therefore, all 16,134 restricted stock shares would vest immediately.

[7] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Johnson was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC). For a detailed description of the accumulated SERP benefit and estimated annual benefit payable at age 65, see "Pension Benefits Table." In the event of early retirement, Mr. Johnson would receive a 2.5% decrease in his accrued SERP benefit for each year that he is younger than age 65.

[8] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, early retirement, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Johnson is not eligible for normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Johnson would forfeit $0 of unvested deferred MICP premiums.

[9] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. In the event of early retirement, Mr. Johnson would receive no additional benefits above what all full-time, non bargaining employees would receive. Mr. Johnson is not eligible for normal retirement. Under involuntary not for cause termination, Mr. Johnson would be reimbursed for 18 months of COBRA premiums at $1,278.98 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Johnson was participating in prior to termination for 36 months at $1,253.90 per month.

[10] Mr. Johnson would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[11] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Johnson. Under IRC Section 280G, Mr. Johnson would be subject to excise tax on $9,400,700 of excess parachute payments above his base amount. Those excess parachute payments result in $1,880,140 of excise taxes, $3,144,621 of tax gross-ups, and $72,859 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Mark F. Mulhern, Senior Vice President and Chief Financial Officer

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$425,000[1]	$0	$0	$0	$1,270,750	$0	$1,317,500	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$233,750	$225,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$429,734	$429,734
2008 (performance period)	$0	$0	$0	$0	$0	$311,963	$198,522
2009 (performance period)	$0	$0	$0	$0	$0	$487,199	$132,872
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$335,831	$335,831
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$48,761	$48,761
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$48,720	$48,720
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$46,587	$46,587
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$46,587	$46,587
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$76,607	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$76,607	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$179,132	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$239,252	$239,252
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$325,876	$0	$0	$325,876	$325,876	$325,876	$325,876
Post-retirement Health Care[8]	$0	$0	$0	$15,249	$0	$19,934	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,459,661	$0
TOTAL	**$325,876**	**$0**	**$0**	**$1,611,875**	**$325,876**	**$5,683,701**	**$2,577,742**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Mulhern's employment agreement requires a severance equal to 2.99 times his then current base salary ($425,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times two plus annual target MICP award times two (($425,000 + $233,750) x 2). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Mulhern would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Mulhern would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $425,000. In the event of death or disability, Mr. Mulhern would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Mulhern's MICP award was $225,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Mulhern would immediately vest 10,566 restricted stock units granted on March 20, 2007; 2,272 restricted stock units granted on March 18, 2008; and would forfeit 8,404 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Mulhern's restricted stock grant dates are beyond the one-year threshold; therefore, all 5,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Mulhern was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Mulhern is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Mulhern would forfeit $0 of unvested deferred MICP premiums.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Mulhern is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Mulhern would be reimbursed for 18 months of COBRA premiums at $847.18 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Mulhern was participating in prior to termination for 24 months at $830.57 per month.

[9] Mr. Mulhern would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Mulhern. Under IRC Section 280G, Mr. Mulhern would be subject to excise tax on $2,691,811 of excess parachute payments above his base amount. Those excess parachute payments result in $538,362 of excise taxes, $900,436 of tax gross-ups, and $20,863 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Jeffrey J. Lyash, Executive Vice President – Corporate Development

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$453,000[1]	$0	$0	$0	$1,354,470	$0	$2,139,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$249,150	$235,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$574,550	$574,550
2008 (performance period)	$0	$0	$0	$0	$0	$442,375	$281,511
2009 (performance period)	$0	$0	$0	$0	$0	$563,108	$153,575
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$433,722	$433,722
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$64,632	$64,632
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$64,591	$64,591
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$88,541	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$88,541	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$170,561	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$157,232	$157,232
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$135,173	$0	$0	$135,173	$135,173	$135,173	$135,173
Post-retirement Health Care[8]	$0	$0	$0	$16,221	$0	$31,807	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,620,699	$0
TOTAL	**$135,173**	**$0**	**$0**	**$1,505,864**	**$135,173**	**$6,954,668**	**$2,730,972**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Lyash's employment agreement requires a severance equal to 2.99 times his then current base salary ($453,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus average MICP award for the three years prior times three (($453,000 + $260,000) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Lyash would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Lyash would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $453,000. In the event of death or disability, Mr. Lyash would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Lyash's MICP award was $235,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Lyash would immediately vest 13,727 restricted stock units granted on March 20, 2007; 3,194 restricted stock units granted on March 18, 2008; and would forfeit 8,477 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Lyash's restricted stock grant dates are beyond the one-year threshold; therefore, all 3,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Lyash was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Lyash is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Lyash would forfeit $0 of unvested deferred MICP premiums.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Lyash is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Lyash would be reimbursed for 18 months of COBRA premiums at $901.19 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Lyash was participating in prior to termination for 36 months at $883.52 per month.

[9] Mr. Lyash would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Lyash. Under IRC Section 280G, Mr. Lyash would be subject to excise tax on $2,988,788 of excess parachute payments above his base amount. Those excess parachute payments result in $597,758 of excise taxes, $999,777 of tax gross-ups, and $23,164 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Lloyd M. Yates, President and Chief Executive Officer, PEC

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$448,000[1]	$0	$0	$0	$1,339,520	$0	$2,083,200	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$246,400	$235,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$574,550	$574,550
2008 (performance period)	$0	$0	$0	$0	$0	$442,375	$281,511
2009 (performance period)	$0	$0	$0	$0	$0	$556,752	$151,841
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$433,722	$433,722
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$64,632	$64,632
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$64,591	$64,591
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$87,515	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$87,556	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$169,576	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$157,232	$157,232
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$499,804	$0	$0	$499,804	$499,804	$499,804	$499,804
Post-retirement Health Care[8]	$0	$0	$0	$23,022	$0	$45,140	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,621,931	$0
TOTAL	**$499,804**	**$0**	**$0**	**$1,862,346**	**$499,804**	**$7,265,962**	**$3,093,869**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Yates' employment agreement requires a severance equal to 2.99 times his then current base salary ($448,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus annual target MICP award times three (($448,000 + $246,400) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Yates would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Yates would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $448,000. In the event of death or disability, Mr. Yates would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009 this is based on the full award. For 2009, Mr. Yates' MICP award was $235,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Yates would immediately vest 13,727 restricted stock units granted on March 20, 2007; 3,194 restricted stock units granted on March 18, 2008; and would forfeit 8,404 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Yates' restricted stock grant dates are beyond the one-year threshold; therefore, all 3,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Yates was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Mr. Yates is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. Yates would forfeit $0 of unvested deferred MICP premiums.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Yates is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Yates would be reimbursed for 18 months of COBRA premiums at $1,278.98 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Yates was participating in prior to termination for 36 months at $1,253.90 per month.

[9] Mr. Yates would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Yates. Under IRC Section 280G, Mr. Yates would be subject to excise tax on $2,991,059 of excess parachute payments above his base amount. Those excess parachute payments result in $598,212 of excise taxes, $1,000,537 of tax gross-ups, and $23,182 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Paula J. Sims, Senior Vice President – Power Operations

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$370,000[1]	$0	$0	$0	$1,106,300	$0	$1,073,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$166,500	$160,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$429,734	$429,734
2008 (performance period)	$0	$0	$0	$0	$0	$330,869	$210,553
2009 (performance period)	$0	$0	$0	$0	$0	$400,176	$109,139
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$335,831	$335,831
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$48,761	$48,761
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$48,720	$48,720
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$49,376	$49,376
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$49,417	$49,417
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$63,442	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$63,442	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$145,503	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$41,010	$41,010
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$414,523	$0	$0	$414,523	$414,523	$444,049	$444,049
Post-retirement Health Care[8]	$0	$0	$0	$5,344	$0	$6,985	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,194,126	$0
TOTAL	**$414,523**	**$0**	**$0**	**$1,526,167**	**$414,523**	**$4,890,941**	**$2,426,590**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Ms. Sims' employment agreement requires a severance equal to 2.99 times her then current base salary ($370,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times two plus target MICP award times two (($370,000 + $166,500) x 2). Does not include impact of long-term disability. In the event of a long-term disability, Ms. Sims would receive 60% of base salary during the period of her disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Ms. Sims would receive 100% of her target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 45% times $370,000. In the event of death or disability, Ms. Sims would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Ms. Sims' MICP award was $160,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Ms. Sims would immediately vest 10,566 restricted stock units granted on March 20, 2007; 2,409 restricted stock units granted on March 18, 2008; and would forfeit 6,642 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Ms. Sims' restricted stock grant dates are beyond the one-year threshold; therefore, all 1,000 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Ms. Sims was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Ms. Sims is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Ms. Sims would forfeit $29,526 of unvested deferred MICP premiums.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Ms. Sims is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Ms. Sims would be reimbursed for 18 months of COBRA premiums at $296.88 per month as provided in her employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Ms. Sims was participating in prior to termination for 24 months at $291.06 per month.

[9] Ms. Sims would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Ms. Sims. Under IRC Section 280G, Ms. Sims would be subject to excise tax on $2,202,132 of excess parachute payments above her base amount. Those excess parachute payments result in $440,426 of excise taxes, $736,633 of tax gross-ups, and $17,067 of employer Medicare tax related to the excise tax payment.

DIRECTOR COMPENSATION

The following includes the required table and related narrative detailing the compensation each director received for his or her services in 2009.

Name (a)	Fees Earned or Paid in Cash[1] ($) (b)	Stock Awards[2] ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation[3] ($) (g)	Total ($) (h)
John D. Baker II	$28,433	$0	—	—	—	$2,186	$30,619
James E. Bostic, Jr.	$93,500	$60,000	—	—	—	$77,502	$231,002
David L. Burner (Retired May 13, 2009)	$51,750	$60,000	—	—	—	$15,640	$127,390
Harris E. DeLoach, Jr.	$103,500	$60,000	—	—	—	$51,844	$215,344
James B. Hyler, Jr.	$95,000	$60,000	—	—	—	$8,899	$163,899
Robert W. Jones	$100,654	$60,000	—	—	—	$35,715	$196,369
W. Steven Jones	$93,500	$60,000	—	—	—	$65,622	$219,122
E. Marie McKee	$107,000	$60,000	—	—	—	$148,522	$315,522
John H. Mullin, III	$108,500	$60,000	—	—	—	$112,871	$281,371
Charles W. Pryor, Jr.	$96,500	$60,000	—	—	—	$18,475	$174,975
Carlos A. Saladrigas	$93,500	$60,000	—	—	—	$58,558	$212,058
Theresa M. Stone	$107,000	$60,000	—	—	—	$57,114	$224,114
Alfred C. Tollison, Jr.	$101,500	$60,000	—	—	—	$50,966	$212,466

[1] Reflects the annual retainer plus any Board or Committee fees earned in 2009. Amounts may have been paid in cash or deferred into the Non-Employee Director Deferred Compensation Plan.

[2] Reflects the grant date fair value of awards granted under the Non-Employee Director Stock Unit Plan in 2009. The assumptions made in the valuation of awards granted pursuant to the Non-Employee Director Stock Unit Plan are not addressed in our consolidated financial statements, footnotes to our consolidated financial statements or in Management's Discussion and Analysis because the Director Plan is immaterial to our consolidated financial statements. As a liability plan under FASB ASC Topic 718, the fair value of the Director Plan is re-measured at each financial statement date. The grant date fair value for each stock unit granted to each director on January 2, 2009 was $40.65. The numbers of stock units outstanding in the Non-Employee Director Stock Unit Plan as of December 31, 2009 for each Director listed above are shown in the table in footnote 3 below.

[3] Includes the following items: The dollar value of dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Stock Unit Plan; dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Deferred Compensation Plan; tax gross-ups; and matching contributions made to eligible nonprofit organizations and to accredited colleges and universities under the Company's now suspended Matching Gifts Program as follows: James E. Bostic, Jr.–$5,500; W. Steven Jones–$2,300; E. Marie McKee–$1,071; and Charles W. Pryor, Jr.–$1,000. The dollar values of dividend reinvestments and unit appreciation for each Director listed above are in the table below. The total value of the perquisites and personal benefits received by each director was less than $10,000. Thus, those amounts are excluded from this column. The numbers of stock units outstanding in the Non-Employee Director Deferred Compensation Plan as of December 3, 2009 for each Director listed above are in the table below.

	Non-Employee Director Stock Unit Plan		**Non-Employee Director Deferred Compensation Plan**	
Name	**Stock Units Outstanding as of Dec. 31, 2009 (see footnote 2 above)**	**Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) (see footnote 3 above)**	**Stock Units Outstanding as of Dec. 31, 2009 (see footnote 3 above)**	**Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) (see footnote 3 above)**
John D. Baker II	0	$0	747	$2,186
James E. Bostic, Jr.	8,396	$29,764	11,260	$42,238
David L. Burner (Retired May 13, 2009)	0	($39,745)	14,682	$54,647
Harris E. DeLoach, Jr.	4,430	$15,147	9,506	$36,697
James B. Hyler, Jr.	1,576	$4,628	1,028	$4,272
Robert W. Jones	3,001	$9,881	6,548	$25,835
W. Steven Jones	5,939	$20,709	11,155	$42,613
E. Marie McKee	11,211	$40,141	28,649	$107,309
John H. Mullin, III	11,700	$41,944	19,113	$70,927
Charles W. Pryor, Jr.	3,001	$9,881	1,930	$7,594
Carlos A. Saladrigas	9,376	$33,378	6,701	$25,181
Theresa M. Stone	5,939	$20,709	9,747	$36,405
Alfred C. Tollison, Jr.	4,430	$15,147	9,131	$35,283

DISCUSSION OF DIRECTOR COMPENSATION TABLE

RETAINER AND MEETING FEES

During 2009, Directors who were not employees of the Company received an annual retainer of $80,000, of which $30,000 was automatically deferred under the Non-Employee Director Deferred Compensation Plan (see below). The Lead Director/Chair of the following Board Committees received an additional retainer of $15,000: Audit and Corporate Performance Committee; Governance Committee; and Organization and Compensation Committee. The Chair of each of the following standing Board Committees received an additional retainer of $10,000: Finance Committee and Operations and Nuclear Oversight Committee. The nonchair members of the following standing Board Committees received an additional retainer of $7,500: Audit and Corporate Performance Committee and the Organization and Compensation Committee. The nonchair members of the following standing Board Committees received an additional retainer of $6,000: Governance Committee; Finance Committee; and Operations and Nuclear Oversight Committee. The Nuclear Oversight Director received an additional retainer of $8,000. The Chair of the Nuclear Project Oversight Committee receives an attendance fee of $2,000 per meeting held by that Committee. Additionally, each member of the Nuclear Project Oversight Committee receives an attendance fee of $1,500 per meeting held by that Committee. Directors who are not employees of the Company received a fee of $1,500 per meeting, paid with the next quarterly retainer, for noncustomary meetings or reviews of the Company's operations that are approved by the Governance Committee. Directors who are employees of our Company do not receive an annual retainer or attendance fees. All Directors are reimbursed for expenses incidental to their service as Directors. Committee positions held by the Directors are discussed in the "Board Committees" section of this Proxy Statement.

The Non-Employee Director Stock Unit Plan provides that each Director will receive an annual grant of stock units that is equivalent to $60,000.

NON-EMPLOYEE DIRECTOR DEFERRED COMPENSATION PLAN

In addition to $30,000 from the annual retainer that is automatically deferred, outside Directors may elect to defer any portion of the remainder of their annual retainer and Board attendance fees until after the termination of their service on the Board under the Non-Employee Director Deferred Compensation Plan. Any deferred fees are deemed to be invested in a number of units of Common Stock of the Company, but participating Directors receive no equity interest or voting rights in any shares of the Common Stock. The number of units credited to the account of a participating Director is equal to the dollar amount of the deferred fees divided by the average of the high and low selling prices (i.e., market value) of the Common Stock on the day the deferred fees would otherwise be payable to the participating Director. The number of units in each account is adjusted from time to time to reflect the payment of dividends on the number of shares of Common Stock represented by the units. Unless otherwise agreed to by the participant and the Board, when the participant ceases to be a member of the Board of Directors, he or she will receive cash equal to the market value of a share of the Company's Common Stock on the date of payment multiplied by the number of units credited to the participant's account.

NON-EMPLOYEE DIRECTOR STOCK UNIT PLAN

Effective January 1, 1998, we established the Non-Employee Director Stock Unit Plan ("Stock Unit Plan"). The Stock Unit Plan provides for an annual grant of stock units equivalent to $60,000 to each non-employee Director. Each unit is equal in economic value to one share of the Company's Common Stock, but does not represent an equity interest or entitle its holder to vote. The number of units is adjusted from time to time to reflect the payment of dividends with respect to the Common Stock of the Company. Benefits under the Stock Unit Plan vest after a participant has been a member of the Board for five years and are payable solely in cash. Effective January 1, 2007, a Director shall be fully vested at all times in the stock units credited to his or her account.

OTHER COMPENSATION

Directors are eligible to receive certain perquisites, including tickets to various cultural arts and sporting events, which are *de minimis* in value. Each retiring Director also receives a gift valued at approximately $1,500 in appreciation for his/her service on the Board.

Additionally, in 2009, directors were eligible to receive a 50 percent match from the Company for contributions made in 2008 to eligible nonprofit organizations and to all accredited colleges and universities. The Company's Matching Gifts Program was suspended as of January 1, 2009.

We charge Directors with imputed income in connection with (i) their travel on Company aircraft for non-Company related purposes and (ii) their spouses' travel on Company aircraft. When spousal travel is at our invitation, we will gross up the Directors for taxes incurred in connection with the imputed income related to the travel.

EQUITY COMPENSATION PLAN INFORMATION
as of December 31, 2009

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	4,414,788	$42.64	6,436,623
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4,414,788	$42.64	6,436,623

Column (a) includes stock options outstanding, outstanding performance units assuming maximum payout potential, and outstanding restricted stock units.

Column (b) includes only the weighted-average exercise price of outstanding options.

Column (c) includes reduction for unissued, outstanding performance units assuming maximum payout potential and unissued, outstanding restricted stock units, and issued restricted stock.

REPORT OF THE AUDIT AND CORPORATE PERFORMANCE COMMITTEE

The Audit and Corporate Performance Committee of the Company's Board of Directors (the "Audit Committee") has reviewed and discussed the audited financial statements of the Company for the fiscal year ended December 31, 2009, with the Company's management and with Deloitte & Touche LLP, the Company's independent registered public accounting firm. The Audit Committee discussed with Deloitte & Touche LLP the matters required to be discussed by Statement on Auditing Standards No. 114, as amended (AICPA, Professional Standards, Vol. 1 AU Section 380) as adopted by the Public Company Accounting Oversight Board in Rule 3200T, by the SEC's Regulation S-X, Rule 2-07, and by the NYSE's Corporate Governance Rules, as may be modified, amended or supplemented.

The Audit Committee has received the written disclosures and the letter from Deloitte & Touche LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communication with the Audit Committee concerning independence and has discussed with Deloitte & Touche LLP its independence.

Based upon the review and discussions noted above, the Audit Committee recommended to the Board of Directors that the Company's audited financial statements be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009, for filing with the SEC.

Audit and Corporate Performance Committee

Theresa M. Stone, Chair
James E. Bostic, Jr.
W. Steven Jones
Melquiades R. "Mel" Martinez*
Charles W. Pryor, Jr.
Carlos A. Saladrigas
Alfred C. Tollison, Jr.

* Mr. Martinez was elected to the Board effective March 1, 2010, and thus did not participate in the reviews and discussions described in the foregoing Report of the Audit Committee.

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Report of the Audit Committee shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

DISCLOSURE OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S FEES

The Audit Committee has actively monitored all services provided by its independent registered public accounting firm, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and non-audit services provided by Deloitte. We have adopted policies and procedures for pre-approving all audit and permissible non-audit services rendered by Deloitte, and the fees billed for those services. Our Controller (the "Controller") is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the pre-approval policy, the Audit Committee specifically pre-approved the use of Deloitte for audit, audit-related and tax services.

The pre-approval policy requires management to obtain specific pre-approval from the Audit Committee for the use of Deloitte for any permissible non-audit services, which generally are limited to tax services, including tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible non-audit services will not be considered for approval except in limited instances, which could include circumstances in which proposed services provide significant economic or other benefits to us. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible non-audit services provided during a fiscal year that (i) do not aggregate more than 5 percent of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as non-audit services at the time of the engagement must be brought to the attention of the Controller for prompt submission to the Audit Committee for approval. These *de minimis* non-audit services must be approved by the Audit Committee or its designated representative before the completion of the services. Non-audit services that are specifically prohibited under the Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting Oversight Board ("PCAOB") rules are also specifically prohibited under the policy.

Prior to approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the service, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between the Company and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than the Company) with respect to the promoting, marketing or recommending of a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and NYSE standards. The Audit Committee will assess the adequacy of this policy as it deems necessary and revise accordingly.

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to us for the fiscal years ended December 31, 2009, and December 31, 2008.

	2009	2008
Audit fees	$3,581,000	$3,673,000
Audit-related fees	91,000	94,000
Tax fees	19,000	22,000
Other fees	—	—
Total Fees	$3,691,000	$3,789,000

Audit fees include fees billed for services rendered in connection with (i) the audits of our annual financial statements and those of our SEC reporting subsidiaries (Carolina Power & Light Company and Florida Power Corporation); (ii) the audit of the effectiveness of our internal control over financial reporting; (iii) the reviews of the financial statements included in our Quarterly Reports on Form 10-Q and those of our SEC reporting subsidiaries; (iv) accounting consultations arising as part of the audits; and (v) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions. Audit fees for 2009 and 2008 also include $1,265,000 and $1,264,000, respectively, for services in connection with the Sarbanes-Oxley Act Section 404 and the related PCAOB Standard No. 2 relating to our internal control over financial reporting.

Audit-related fees include fees billed for (i) special procedures and letter reports; (ii) benefit plan audits when fees are paid by us rather than directly by the plan; and (iii) accounting consultations for prospective transactions not arising directly from the audits.

Tax fees include fees billed for tax compliance matters and tax planning and advisory services.

The Audit Committee has concluded that the provision of the non-audit services listed above as "Tax fees" is compatible with maintaining Deloitte's independence.

None of the services provided required approval by the Audit Committee pursuant to the *de minimis* waiver provisions described above.

PROPOSAL 2—RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit and Corporate Performance Committee of our Board of Directors (the "Audit Committee") has selected Deloitte & Touche LLP ("Deloitte & Touche") as our independent registered public accounting firm for the fiscal year ending December 31, 2010, and has directed that management submit the selection of that independent registered public accounting firm for ratification by the shareholders at the 2010 Annual Meeting of the Shareholders. Deloitte & Touche has served as the independent registered public accounting firm for our Company and its predecessors since 1930. In selecting Deloitte & Touche, the Audit Committee considered carefully Deloitte & Touche's previous performance for us, its independence with respect to the services to be performed and its general reputation for adherence to professional auditing standards. A representative of Deloitte & Touche will be present at the Annual Meeting of Shareholders, will have the opportunity to make a statement and will be available to respond to appropriate questions. Shareholder ratification of the selection of Deloitte & Touche as our independent registered public accounting firm is not required by our By-Laws or otherwise. However, we are submitting the selection of Deloitte & Touche to the shareholders for ratification as a matter of good corporate practice. If the shareholders fail to ratify the selection, the Audit Committee will reconsider whether or not to retain Deloitte & Touche. Even if the shareholders ratify the selection, the Audit Committee, in its discretion, may direct the appointment of a different independent registered public accounting firm at any time during the year if it is determined that such a change would be in the best interest of the Company and its shareholders.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where no specification is made, the shares represented by the accompanying proxy will be voted "**FOR**" the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm. Votes (other than votes withheld) will be cast pursuant to the accompanying proxy for the ratification of the selection of Deloitte & Touche.

The proposal to ratify the selection of Deloitte & Touche to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2010, requires approval by a majority of the votes actually cast by holders of Common Stock present in person or represented by proxy at the Annual Meeting of Shareholders and entitled to vote thereon. Abstentions from voting and broker nonvotes will not count as shares voted and will not have the effect of a "negative" vote, as described in more detail under the heading "PROXIES" on page 2.

The Audit Committee and the Board of Directors recommend a vote "**FOR**" the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm.

PROPOSAL 3—ADOPTION OF A "HOLD-INTO-RETIREMENT" POLICY FOR EQUITY AWARDS

One of our shareholders has submitted the proposal set forth below relating to the adoption of a "hold-into-retirement" policy for equity awards. Upon written or oral request, the Company will provide the name, address and share ownership of the proponent. Any such requests should be directed to our Corporate Secretary. For the reasons set forth after the proposal, the Board recommends a vote **"AGAINST"** the proposal.

Resolved: That stockholders of Progress Energy, Inc. ("Company") urge the Compensation Committee of the Board of Directors (the "Committee") to adopt a policy requiring that senior executives retain a significant percentage of shares acquired through equity compensation programs until two years following the termination of their employment (through retirement or otherwise), and to report to stockholders regarding the policy before Company 2011 annual meeting of stockholders. The stockholders recommend that the Committee not adopt a percentage lower than 75% of net after-tax shares. The policy should address the permissibility of transactions such as hedging transactions which are not sales but reduce the risk of loss to the executive.

Supporting Statement:

Equity-based compensation is an important component of senior executive compensation at the Company.

Requiring senior executives to hold a significant portion of shares obtained through compensation plans after the termination of employment would focus them on Company long-term success and would better align their interests with those of Company stockholders. In the context of the current financial climate, we believe it is imperative that companies reshape their compensation policies and practices to discourage excessive risk-taking and promote long-term, sustainable value creation. A 2002 report by a commission of The Conference Board endorsed the idea of a holding requirement, stating that the long-term focus promoted thereby "may help prevent companies from artificially propping up stock prices over the short-term to cash out options and making other potentially negative short-term decisions."

The Company has established stock ownership guidelines for executive officers. The guidelines were increased in 2009 to a minimum level of ownership of five times base salary for the Chief Executive Officer ("CEO"), four times base salary for the Chief Operating Officer ("COO"), and three times base salary for the Chief Financial Officer and Presidents/Executive Vice Presidents/Senior Vice Presidents.

We believe this policy does not go far enough to ensure that equity compensation builds executive ownership. We also view a retention requirement approach as superior to a stock ownership guideline because a guideline loses effectiveness once it has been satisfied.

We urge stockholders to vote for this proposal.

COMPANY RESPONSE

The Board and management oppose this shareholder proposal and recommend a vote "AGAINST" the proposal for the reasons set forth below:

The Board has considered this proposal and believes that its adoption is unnecessary and not in the best interests of the Company or its shareholders. For the reasons discussed below, the Board recommends that you vote **"AGAINST"** adoption of this proposal.

- **The Board of Directors believes that the Company's equity compensation policies have been essential to attracting and retaining experienced and effective executives and motivating them to perform in the best interests of the Company and its shareholders.**

The Board of Directors believes strongly that equity compensation and mandatory equity ownership promote accountability and encourage executives to enhance long-term shareholder value. This belief is reflected in our compensation policies and practices. Equity ownership is a fundamental element of the Company's executive compensation program and provides an essential source of incentive and motivation for our senior executives. Approximately 60% of total target compensation for our executive officers is provided in equity and focused on long-term performance. The Company's executive compensation program is carefully designed to provide a competitive level of at-risk and performance-based incentives through a combination of equity awards, including restricted stock units and performance shares. The Board believes that the proposal would result in an overemphasis on post-retirement compensation and undermine the effectiveness of the Company's existing executive compensation programs.

- **The Board believes that our stock ownership guidelines ensure that the Company's executive officers have a significant equity stake in the future of the Company.**

The Company's stock ownership guidelines are consistent with those of the peer group the Organization and Compensation Committee used to benchmark compensation and with which we compete for executive talent. Our guidelines are consistent with the 50th percentile for both the base salary multiple and the time required to meet ownership targets. The Company's CEO currently holds 8.5 times his base salary although our guidelines require him to hold 5 times his base salary in equity compensation. All of our senior executives are in compliance with the Company's stock ownership guidelines.

The proposal states that the two-year post retirement retention approach is "superior" because the guideline approach loses effectiveness once the guidelines have been met. The Board of Directors does not believe this is true, as executives are continually expected to meet the guidelines, even during market downturns. Moreover, the ownership levels established in the guidelines represent a significant amount of money and, as a result, are a regular and strong source of alignment with shareholders' interests. Finally, three to five times an executive's salary is a significant amount that is not easily dismissed just because further accumulation of equity is no longer necessary.

- **Because we are in a highly regulated industry, our compensation programs do not provide incentives for executive officers to take unnecessary and excessive risks that threaten the value of the Company.**

Post-termination holding periods are purported to prevent executives from taking actions that would cause the price of a company's stock to rise as they depart in order for them to be able to sell their holdings at an elevated price before their behavior is discovered and corrected. As an integrated electric utility, primarily engaged in the regulated utility business, the Company is highly regulated at both the federal and state levels. State and federal regulators set the parameters within which the Company can operate. The state regulators have authority to review and approve the rates we charge our customers. The regulators review certain of our costs and investments, and approve our recovery of them from customers only if they determine that the costs and investments were reasonable and prudent when incurred. In such a regulated environment, excessive risk-taking is neither encouraged nor allowed. Therefore, it is highly unlikely our executives would be able to successfully engage in the type of behavior the proposal is intended to protect against.

- **The Board believes that the type of policy mandated by the proposal, with its high retention threshold and post-retirement holding period, is not a prevalent practice and may lead to an early loss of executive talent.**

The two-year post termination requirement would limit our executives' financial resources at a time when they no longer have any control over our operations or results. Long-term alignment is, of course, important. However, for our compensation programs to have value, participants should be permitted the flexibility for some degree of diversification. In the absence of this balanced approach, executives who have been successful in enhancing shareholder value may choose to leave the Company earlier than they otherwise would if they are interested in selling any of their shares in order to share in the value they have helped to create. As a result, the proposal could lead to an early loss of experienced talent and make it more difficult and costly to attract, motivate and retain executives.

- **The Board believes that the type of policy mandated by the proposal will result in executives' failure to take the actions needed to ensure the Company's long-term success.**

As noted above, the Company is a member of a highly regulated industry in which excessive risk-taking is neither encouraged nor allowed. The Company recognizes, however, that **some** amount of risk-taking is inherent in its business and is necessary in order to increase profitability and long-term shareholder value. If executives are too focused on preserving the value of their equity holdings in the Company into retirement, they may become reluctant to pursue strategies or undertake projects or capital investments that could be beneficial to the Company. The proposed policy would leave our executives almost completely dependent on the value of the Company stock, potentially resulting in them becoming unduly risk averse to the detriment of our shareholders.

The Board of Directors remains committed to the design and implementation of equity compensation programs and stock ownership guidelines that best align the interests of the Company's leadership with those of our shareholders, provide competitive compensation that requires executives to own a significant portion of Company stock and ensure that executives have the appropriate flexibility to manage their personal financial affairs. We believe the Company's existing programs and guidelines achieve these objectives and are essential to our ability to attract, motivate and retain talented executives.

YOUR BOARD OF DIRECTORS AND MANAGEMENT URGE YOU TO VOTE <u>AGAINST</u> THIS PROPOSAL

FINANCIAL STATEMENTS

Our 2009 Annual Report, which includes financial statements as of December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, together with the report of Deloitte & Touche LLP, our independent registered public accounting firm, was mailed to those who were shareholders of record as of the close of business on March 5, 2010.

FUTURE SHAREHOLDER PROPOSALS

Shareholder proposals submitted for inclusion in the proxy statement for our 2011 Annual Meeting must be received no later than December 1, 2010, at our principal executive offices, addressed to the attention of:

John R. McArthur
Executive Vice President and Corporate Secretary
Progress Energy, Inc.
P.O. Box 1551
Raleigh, North Carolina 27602-1551

Upon receipt of any such proposal, we will determine whether or not to include such proposal in the proxy statement and proxy in accordance with regulations governing the solicitation of proxies.

In order for a shareholder to nominate a candidate for director, under our By-Laws timely notice of the nomination must be received by the Corporate Secretary of the Company either by personal delivery or by United States registered or certified mail, postage pre-paid, not later than the close of business on the 120th calendar day before the date our proxy statement was released to shareholders in connection with the previous year's annual meeting. In no event shall the public announcement of an adjournment or postponement of an annual meeting or the fact that an annual meeting is held after the anniversary of the preceding annual meeting commence a new time period for a shareholder's giving of notice as described above. The shareholder filing the notice of nomination must include:

- As to the shareholder giving the notice:
  - the name and address of record of the shareholder who intends to make the nomination, the beneficial owner, if any, on whose behalf the nomination is made and of the person or persons to be nominated;
  - the class and number of our shares that are owned by the shareholder and such beneficial owner;
  - a representation that the shareholder is a holder of record of our shares entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; and
  - a description of all arrangements, understandings or relationships between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder.
- As to each person whom the shareholder proposes to nominate for election as a director:
  - the name, age, business address and, if known, residence address of such person;
  - the principal occupation or employment of such person;
  - the class and number of shares of our stock that are beneficially owned by such person;

– any other information relating to such person that is required to be disclosed in solicitations of proxies for election of directors or is otherwise required by the rules and regulations of the SEC promulgated under the Securities Exchange Act of 1934; and

– the written consent of such person to be named in the proxy statement as a nominee and to serve as a director if elected.

In order for a shareholder to bring other business before a shareholder meeting, we must receive timely notice of the proposal not later than the close of business on the 60th day before the first anniversary of the immediately preceding year's annual meeting. Such notice must include:

- the information described above with respect to the shareholder proposing such business;
- a brief description of the business desired to be brought before the annual meeting, including the complete text of any resolutions to be presented at the annual meeting, and the reasons for conducting such business at the annual meeting; and
- any material interest of such shareholder in such business.

These requirements are separate from the requirements a shareholder must meet to have a proposal included in our proxy statement.

Any shareholder desiring a copy of our By-Laws will be furnished one without charge upon written request to the Corporate Secretary. A copy of the By-Laws, as amended and restated on May 10, 2006, was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, and is available at the SEC's Web site at *www.sec.gov*.

OTHER BUSINESS

The Board of Directors does not intend to bring any business before the meeting other than that stated in this Proxy Statement. The Board knows of no other matter to come before the meeting. If other matters are properly brought before the meeting, it is the intention of the Board of Directors that the persons named in the enclosed proxy will vote on such matters pursuant to the proxy in accordance with their best judgment.

Exhibit A

POLICY AND PROCEDURES WITH RESPECT TO RELATED PERSON TRANSACTIONS

A. Policy Statement

The Company's Board of Directors (the "Board") recognizes that Related Person Transactions (as defined below) can present heightened risks of conflicts of interest or improper valuation or the perception thereof. Accordingly, the Company's general policy is to avoid Related Person Transactions. Nevertheless, the Company recognizes that there are situations where Related Person Transactions might be in, or might not be inconsistent with, the best interests of the Company and its stockholders. These situations could include (but are not limited to) situations where the Company might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when the Company provides products or services to Related Persons (as defined below) on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. The Company, therefore, has adopted the procedures set forth below for the review, approval or ratification of Related Person Transactions.

This Policy has been approved by the Board. The Corporate Governance Committee (the "Committee") will review and may recommend to the Board amendments to this Policy from time to time.

B. Related Person Transactions

For the purposes of this Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness, (or any series of similar transactions, arrangements or relationships) in which the Company (including any of its subsidiaries) was, is or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest.

For purposes of this Policy, a "Related Person" means:

1. any person who is, or at any time since the beginning of the Company's last fiscal year was, a director or executive officer (i.e. members of the Senior Management Committee and the Controller) of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc. or a nominee to become a director of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc.;

2. any person who is known to be the beneficial owner of more than 5% of any class of the voting securities of the Company or its subsidiaries;

3. any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of the director, executive officer, nominee or more than 5% beneficial owner, and any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee or more than 5% beneficial owner; and

4. any firm, corporation or other entity in which any of the foregoing persons is employed or is a general partner or principal or in a similar position or in which such person has a 5% or greater beneficial ownership interest.

C. Approval Procedures

1. The Board has determined that the Committee is best suited to review and approve Related Person Transactions. Accordingly, at each calendar year's first regularly scheduled Committee meeting, management shall recommend Related Person Transactions to be entered into by the Company for that calendar year, including the proposed aggregate value of such transactions if applicable. After review, the Committee shall approve or disapprove such transactions and at each subsequently scheduled meeting, management shall update the Committee as to any material change to those proposed transactions.

2. In determining whether to approve or disapprove each related person transaction, the Committee will consider various factors, including the following:

   - the identity of the related person;
   - the nature of the related person's interest in the particular transaction;
   - the approximate dollar amount involved in the transaction;
   - the approximate dollar value of the related person's interest in the transaction;
   - whether the related person's interest in the transaction conflicts with his obligations to the Company and its shareholders;
   - whether the transaction will provide the related person with an unfair advantage in his dealings with the Company; and
   - whether the transaction will affect the related person's ability to act in the best interests of the Company and its shareholders

   The Committee will only approve those related person transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

3. In the event management recommends any further Related Person Transactions subsequent to the first calendar year meeting, such transactions may be presented to the Committee for approval at the next Committee meeting. In these instances in which the Legal Department, in consultation with the President and Chief Operating Officer, determines that it is not practicable or desirable for the Company to wait until the next Committee meeting, any further Related Person Transactions shall be submitted to the Chair of the Committee (who will possess delegated authority to act between Committee meetings). The Chair of the Committee shall report to the Committee at the next Committee meeting any approval under this Policy pursuant to his/her delegated authority.

4. No member of the Committee shall participate in any review, consideration or approval of any Related Person Transaction with respect to which such member or any of his or her immediate family members is the Related Person. The Committee (or the Chair) shall approve only those Related Person Transactions that are in, or are not inconsistent with, the best interests of the Company and its stockholders, as the Committee (or the Chair) determines in good faith. The Committee or Chair, as applicable, shall convey the decision to the President and Chief Operating Officer, who shall convey the decision to the appropriate persons within the Company.

D. Ratification Procedures

In the event the Company's Chief Executive Officer, President and Chief Operating Officer, Chief Financial Officer or General Counsel becomes aware of a Related Person Transaction that has not been previously approved or previously ratified under this Policy, said officer shall immediately notify the Committee or Chair of the Committee, and the Committee or Chair shall consider all of the relevant facts and circumstances regarding the Related Person Transaction. Based on the conclusions reached, the Committee or the Chair shall evaluate all options, including but not limited to ratification, amendment, termination or recession of the Related Person Transaction, and determine how to proceed.

E. Review of Ongoing Transactions

At the Committee's first meeting of each calendar year, the Committee shall review any previously approved or ratified Related Person Transactions that remain ongoing and have a remaining term of more than six months or remaining amounts payable to or receivable from the Company of more than $120,000. Based on all relevant facts and circumstances, taking into consideration the Company's contractual obligations, the Committee shall determine if it is in the best interests of the Company and its stockholders to continue, modify or terminate the Related Person Transaction.

F. Disclosure

All Related Person Transactions are to be disclosed in the filings of the Company, Progress Energy Carolinas, Inc. or Progress Energy Florida, Inc., as applicable, with the Securities and Exchange Commission as required by the Securities Act of 1933 and the Securities Exchange Act of 1934 and related rules. Furthermore, all Related Person Transactions shall be disclosed to the Corporate Governance Committee of the Board and any <u>material</u> Related Person Transaction shall be disclosed to the full Board of Directors.

The material features of this Policy shall be disclosed in the Company's annual report on Form 10-K or in the Company's proxy statement, as required by applicable laws, rules and regulations.

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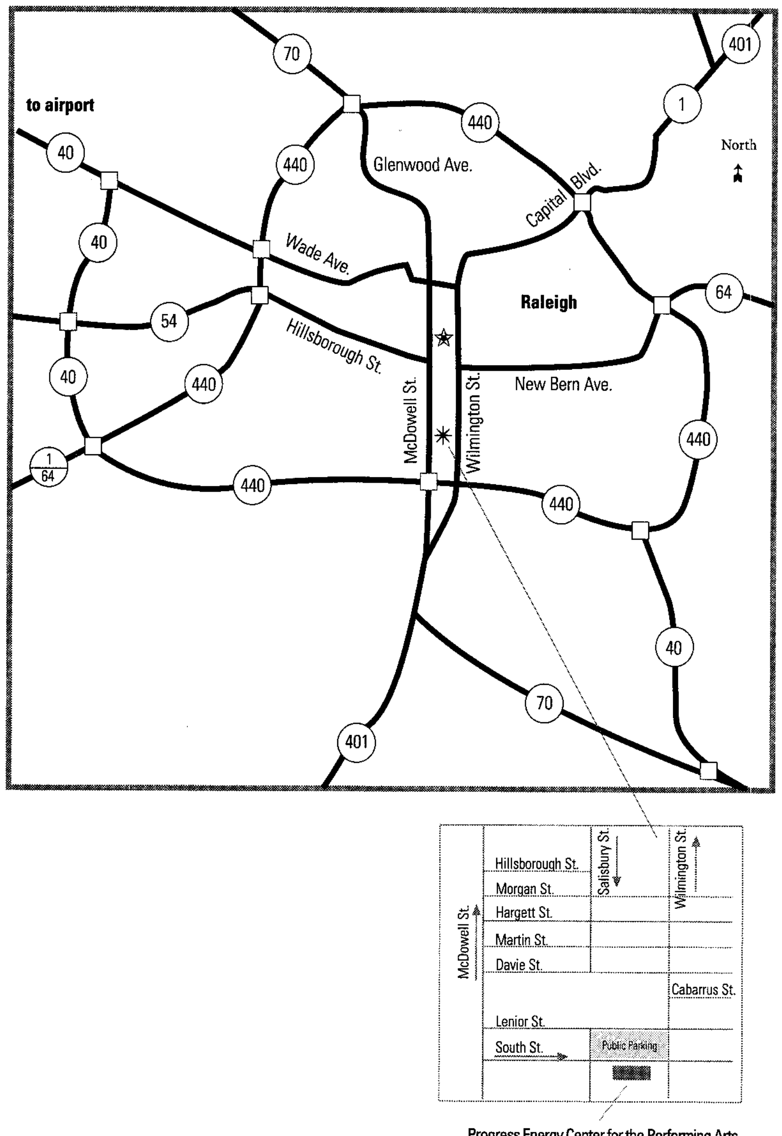
Directions to Progress Energy's 2010 Annual Shareholders' Meeting

Progress Energy Center for the Performing Arts
2 E. South Street, Raleigh, North Carolina



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Board of Directors

William D. Johnson

Chairman, President and Chief Executive Officer, Progress Energy, Inc. Raleigh, N.C.

Elected to the board in 2007. Serves as Chairman, Progress Energy Carolinas and Chairman, Progress Energy Florida.

John D. Baker II

President and Chief Executive Officer, Patriot Transportation Holding, Inc. (provides transportation services and real estate operations). Jacksonville, Fla.

Elected to the board in 2009 and sits on the following committees: Finance; Organization and Compensation.

James E. Bostic, Jr.

Managing Director, HEP & Associates (business consulting) and retired Executive Vice President, Georgia-Pacific Corp. (manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals). Atlanta, Ga.

Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Harris E. DeLoach, Jr.

Chairman, President and Chief Executive Officer, Sonoco Products Co. (manufacturer of paperboard and paper and plastic packaging products). Hartsville, S.C.

Elected to the board in 2006 and sits on the following committees: Corporate Governance; Nuclear Project Oversight; Operations and Nuclear Oversight (Chair); Organization and Compensation.

James B. Hyler, Jr.

Retired Vice Chairman and Chief Operating Officer, First Citizens Bank. Raleigh, N.C.

Elected to the board in 2008 and sits on the following committees: Finance; Organization and Compensation.

Robert W. Jones

Sole owner, Turtle Rock Group, LLC (financial advisory consulting firm). Bedford, N.Y.

Elected to the board in 2007 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

W. Steven Jones

Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill and formerly Chief Executive Officer of Suncorp-Metway Ltd. (banking and insurance in Australia). Chapel Hill, N.C.

Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Melquiades R. "Mel" Martinez

Partner, specializing in public policy, DLA Piper (an international law firm) and former U.S. Senator from the state of Florida and former Secretary of the U.S. Department of Housing and Urban Development. Orlando, Fla.

Elected to the board in 2010 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

E. Marie McKee

Senior Vice President, Corning, Inc. (manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences). Corning, N.Y.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; Nuclear Project Oversight; Operations and Nuclear Oversight; Organization and Compensation (Chair).

John H. Mullin, III

Chairman, Ridgeway Farm, LLC (farming and timber management) and formerly a Managing Director, Dillon, Read & Co. (investment bankers). Brookneal, Va.

Elected to the board in 1999, Lead Director, and sits on the following committees: Corporate Governance (Chair); Finance; Organization and Compensation.

Charles W. Pryor, Jr.

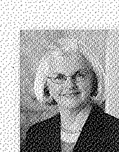
Chairman, Urenco Investments, Inc. (global provider of services and technology to the nuclear generation industry). Lynchburg, Va.

Elected to the board in 2007 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight (Chair); Operations and Nuclear Oversight.

Carlos A. Saladrigas

Chairman and Chief Executive Officer, Regis HRG (provides a full suite of outsourced human resources services to small and midsized businesses). Previously served as Chairman, Premier American Bank and retired Chief Executive Officer, ADP TotalSource. Miami, Fla.

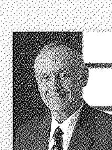
Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.



Theresa M. Stone

Executive Vice President and Treasurer, Massachusetts Institute of Technology and retired President, Lincoln Financial Media (financial services company). Boston, Mass.

Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.



Alfred C. Tollison, Jr.

Retired Chairman and Chief Executive Officer, Institute of Nuclear Power Operations (a nuclear industry-sponsored nonprofit organization). Marietta, Ga.

Elected to the board in 2006 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight (Vice Chair); Operations and Nuclear Oversight.

Progress Energy

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Raleigh, N.C. 27602-1551
progress-energy.com

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