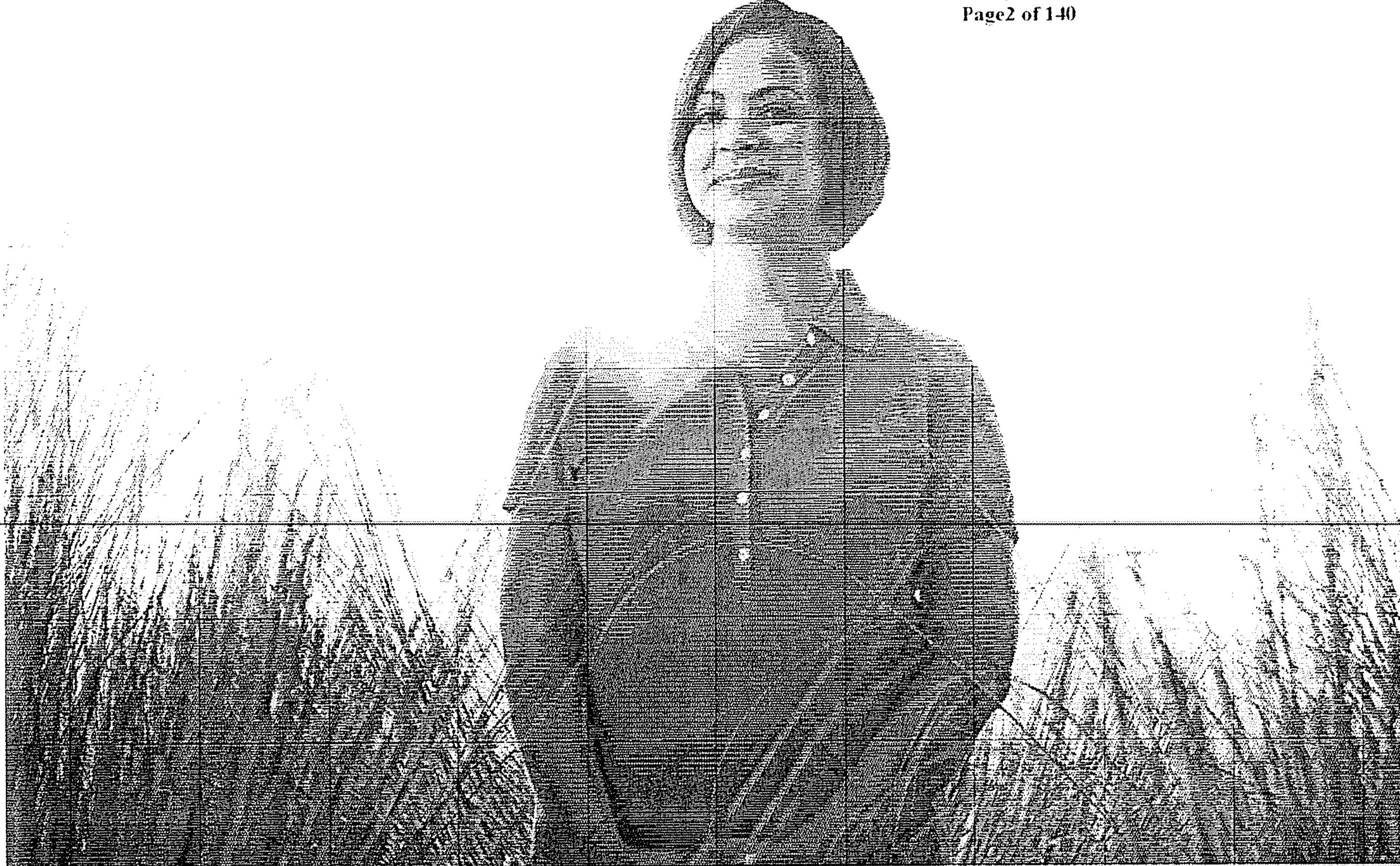
Volumes 8E - 8F

WE'RE LOOKING AT POWER IN A NEW LIGHT.

Progress Energy

ANNUAL REPORT



We talk to customers every day so we know what they care about most. They want the lights to come on every time they flip the switch. They want real ways to save energy and money. Above all, they want to know we are working hard to ensure clean, reliable, affordable power. And every day, I have the satisfaction of assuring them that's exactly what we're doing.

— Kisha Camacho
Customer and Market Services
Progress Energy Florida

BRIGHT THINKING

FOR TODAY'S ENERGY LANDSCAPE.

At Progress Energy, we have one of the most powerful tools in the industry: the power of intelligent, innovative thinking. And we are focusing this powerful tool on our two regulated electric utilities, Progress Energy Carolinas and Progress Energy Florida. Our more than 10,000 employees are developing the best solutions for the energy challenges of today and tomorrow. We are implementing a Balanced Solution for meeting our growing area's energy needs, combining energy efficiency, alternative energy and state-of-the-art power generation. And we are working in partnership with our communities, building public and regulatory support. In short, we are developing a bright future for our company, customers and shareholders. And we're succeeding because every one of us is looking at power in a new light.

ENERGY EFFICIENCY
ALTERNATIVE ENERGY
STATE-OF-THE-ART PLANTS

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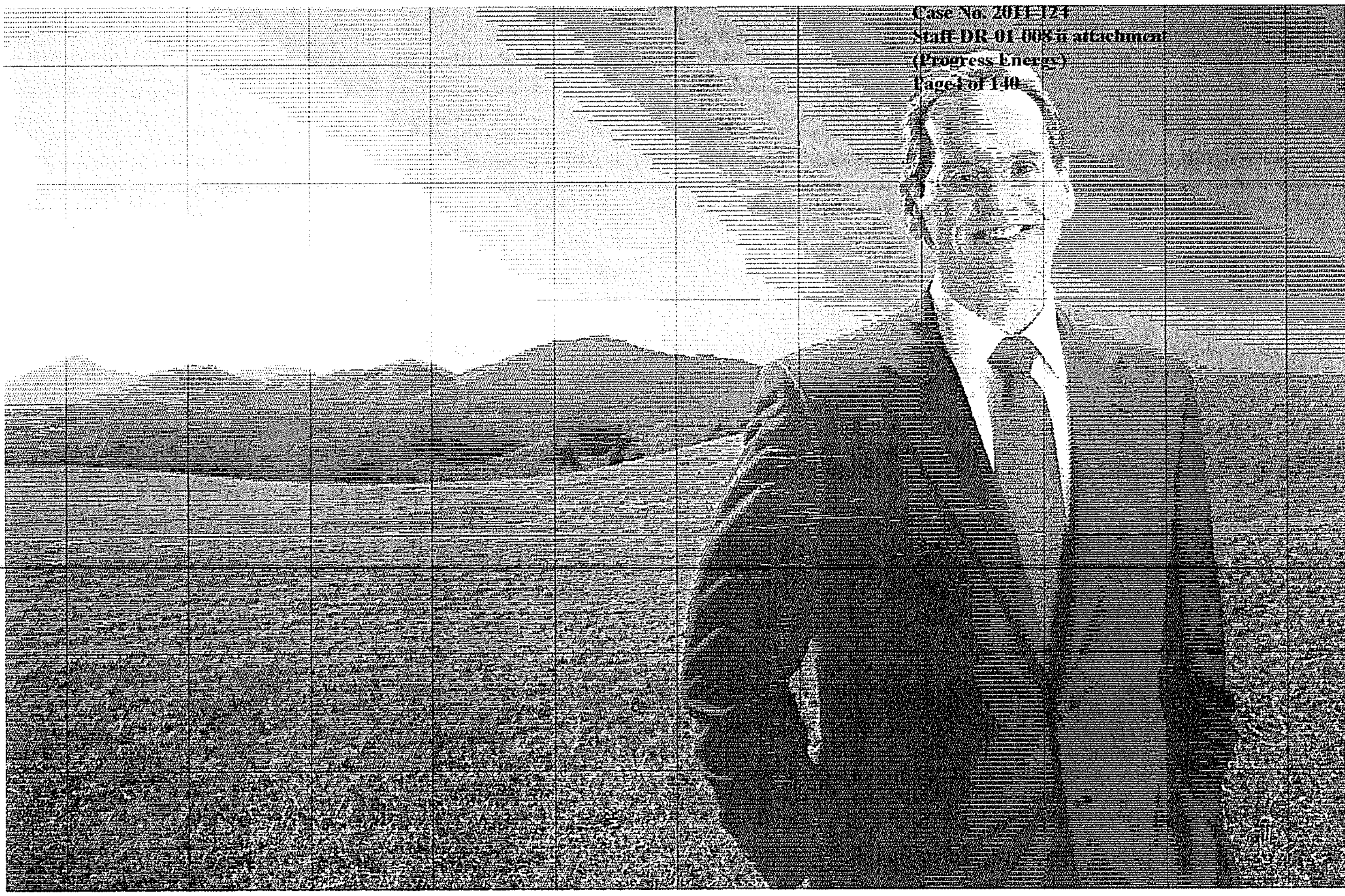


DEAR SHAREHOLDERS:

Our company produced strong results for customers and shareholders in 2007, and is adapting well to an industry landscape being shaped by climate change concerns and the growing demand for electricity. Focused on our two electric utilities, Progress Energy has a balanced strategy for long-term success. I'm optimistic about securing our energy future, in part because we're "looking at power in a new light."

I am pleased to report that in 2007 we increased our dividend for the 20th year in a row while delivering excellent service to our 3.1 million customers. We also once again met our core ongoing earnings-per-share target and further strengthened our balance sheet and credit quality. In late 2007, we announced the sale of the last of our non-utility subsidiaries, completing the transition back to our core business.

Sustaining this strategic focus and financial strength is critical as we prepare for the major construction projects ahead. For years to come, we will be investing heavily in the electric utility infrastructure necessary to keep up with population growth and new environmental and energy regulations.

People continue moving to the states where we provide retail electric service. Florida, North Carolina and South Carolina are all among the nation's top 10 in population growth, according to the U.S. Census Bureau. Our company's responsibility, as well as our business opportunity, is to be ready with the right mix of clean, reliable and cost-effective resources.

NEW REALITIES. In many ways, it's a new day in our industry. The single biggest issue is how best to meet the challenge of global climate change and population growth while ensuring reliable, affordable power for the future. This year, Progress Energy will issue an updated version of our 2006 report on climate change. We are working collaboratively with government leaders and others to develop consensus-based public policies to address this vital issue.

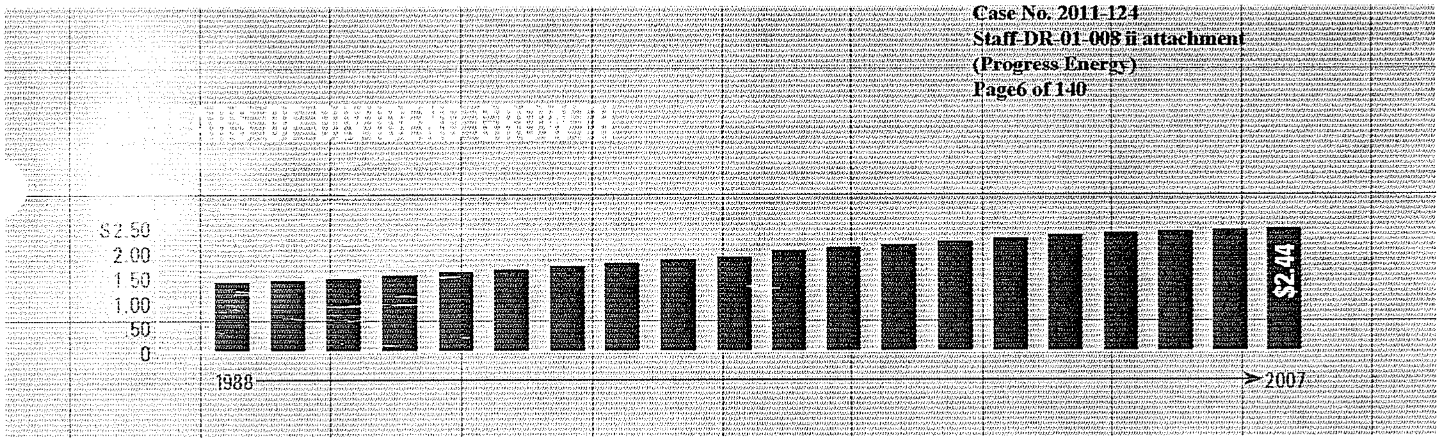
The new energy realities also include rising costs, emerging technologies and a groundswell of support for greater energy efficiency and alternative energy sources. Although challenges certainly remain, the prospects for building new state-of-the-art nuclear power plants are the best in many years.

It has become increasingly difficult to add new coal-fired generation without being able to capture and store the carbon emissions, and the nation must avoid over-reliance on natural gas as a fuel source because of its volatile price and uncertain supply. So, experts and policy-makers from a broad spectrum of interests now recognize that expanded

FINANCIAL HIGHLIGHTS

Years ended December 31 (in millions, except per share data)	2007	2006*	2005*
Financial Data			
Operating revenues	**$9,153**	$8,724	$7,948
Net income	**504**	571	697
Income from continuing operations	**693**	551	523
Core ongoing earnings per common share**	**2.81**	2.63	2.70
Reported GAAP earnings per common share	**1.97**	2.28	2.82
Average common shares outstanding	**256**	250	247
Common Stock Data			
Return on average common stock equity (percent)	**5.97**	7.05	8.91
Book value per common share	**$32.66**	$32.71	$32.35
Market value per common share (closing)	**$48.43**	$49.08	$43.92

**Financial data has been restated for discontinued operations.*
***See page 134 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*



use of nuclear energy is an essential part of getting serious about addressing climate change.

SECURING THE FUTURE. To adapt to today's changing energy landscape, Progress Energy is implementing a balanced three-part strategy of aggressive energy efficiency, innovative alternative energy and state-of-the-art power plants. This annual report describes just a few examples of how we're moving forward on these three fronts.

Progress Energy Carolinas in 2007 doubled its energy-efficiency goal and announced an array of new efficiency initiatives, including a partnership to promote the use of compact fluorescent lights (CFLs). We solicited proposals for renewable energy projects and actively worked alongside diverse groups in the passage of new energy legislation in North Carolina and South Carolina. The North Carolina law established the first renewable energy standard in the Southeast.

Also in 2007, we announced a new natural gas-fired unit in Richmond County, N.C., and in early 2008 filed a federal license application for a potential new nuclear plant in Wake County, N.C. This keeps our option open on this project, but it is not yet a decision to build a new nuclear plant.

Meanwhile, Progress Energy Florida expanded its aggressive efficiency program, signed contracts for more renewable energy projects and launched a much-praised *SolarWise for Schools*℠ program. We also completed a new gas-fired unit at our Hines Energy Complex in Polk County, Fla.

In 2008 we plan to submit a federal license application and seek state approval for a potential new nuclear plant in Levy County, Fla. Given the growth in Florida, this nuclear project will likely be on a faster track than the one in North Carolina.

THE PEOPLE. My goal is to bring out the best in the people who work here so together we can bring out the best in Progress Energy. You will meet a few of our many talented employees in this report. More than 10,000 others have their own stories to tell.

I'm proud of this company's legacy of safety, integrity and service. We are building on that record while being innovative in meeting the new energy realities of 2008 and beyond. Our employees are savvy about the changes in our industry and are deeply committed to our service mission. They feel the responsibility of having millions of people depend on us every hour of every day.

The way our people strive to produce operational excellence day after day and superior financial results year after year inspires me. Together, we're creating a great place to work for all kinds of people willing to perform to high standards – a place where we treat everyone with dignity, respect and fairness, and engage everyone in securing a strong future.

Before ending this letter, I want to say a word about Bob McGehee, our chairman and CEO who died suddenly last October, just months before retiring. Bob was a kind, gracious man, insightful about this business and about life. He was an important mentor to me. As always, he had planned well and had this company ready for a smooth leadership transition.

Now, more than five months later, I think Bob would be proud of what we're doing to build on Progress Energy's positive momentum: the additional steps we're taking to prepare for the future and the responsible leadership we're showing in tackling the hard issues such as climate change.

I am privileged to be in this position, surrounded by a capable, forward-looking team, at this point in the history of our company and industry. I am energized by what we can accomplish for our company, for the communities we serve and for all who rely on us.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2008

A LEGACY OF EXCELLENCE

A Tribute To Bob McGehee

CHAIRMAN AND CEO OF PROGRESS ENERGY, 2004 – 2007

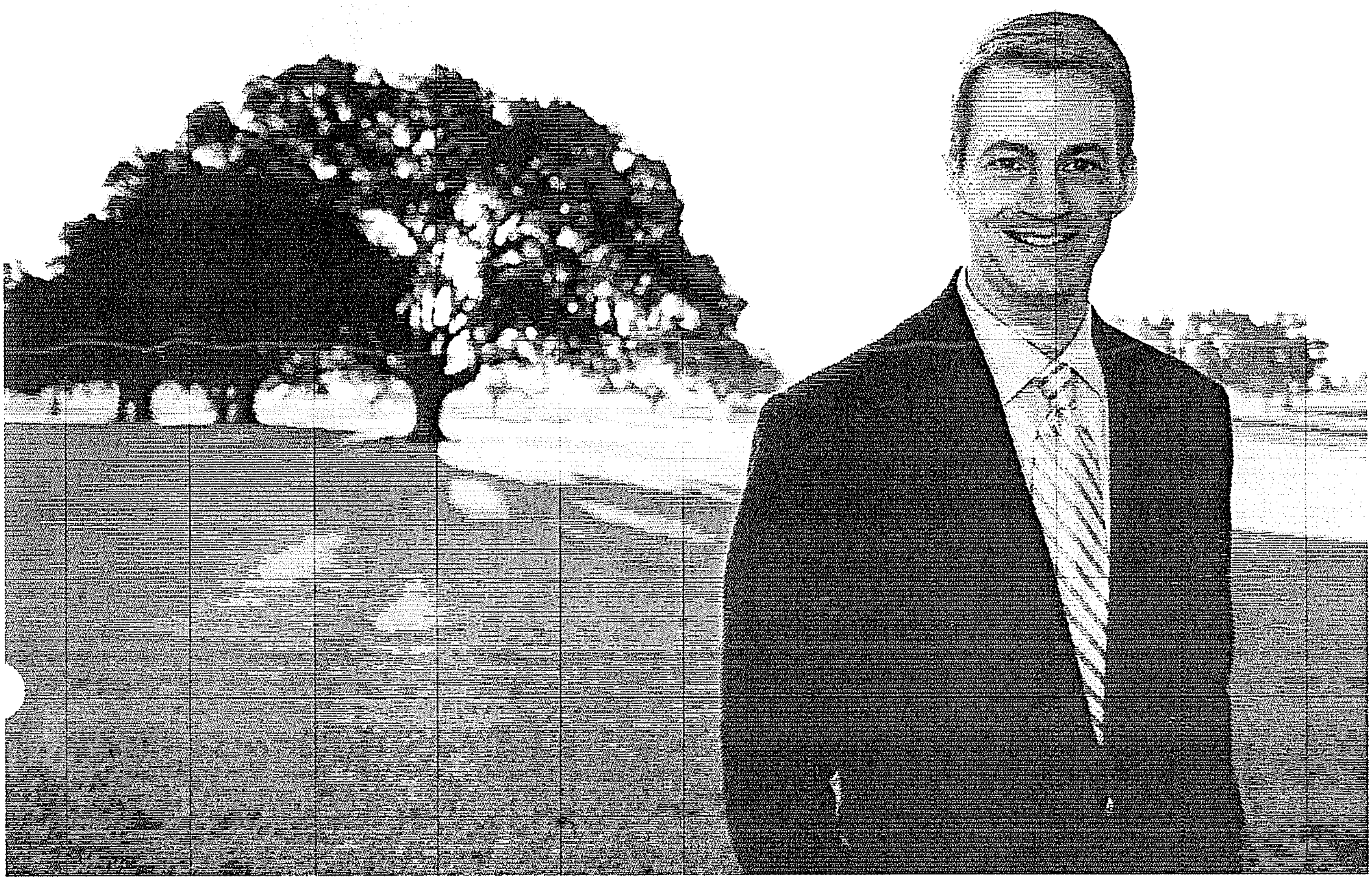
Bob McGehee joined Progress Energy, then CP&L, in 1997. Both wise and humble, he possessed the rare ability to engage meaningfully with employees, investors, customers and community leaders. Every day, he represented Progress Energy at its best through his personal example of integrity and caring.

With a clear strategic focus and steady hand, Bob McGehee navigated Progress Energy through a period of tremendous change in the industry and the company itself. Under his leadership, the company successfully divested noncore subsidiaries to focus on our two regulated utilities, bringing both to a level of industry-recognized excellence. He also guided the development of a long-term strategic plan to maintain our track record of operational excellence, environmental responsibility and customer commitment. His legacy of excellence will continue as a vital part of Progress Energy's future.

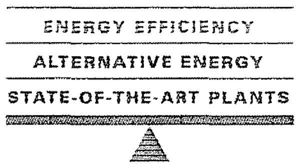
LOOKING AT ENERGY EFFICIENCY IN A NEW LIGHT.

Energy efficiency succeeds on many levels. We partner with our customers to develop the energy-efficiency programs that work for their lifestyles – and save them money every day.

— *Chris Edge*
Manager, DSM and Alternative Energy Strategies
Progress Energy Carolinas



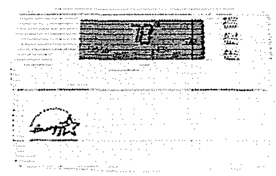
A CHANGING ENERGY LANDSCAPE. Clean, reliable, affordable power is our fundamental commitment. Today we face new energy realities, including rising energy prices and environmental concerns. But at Progress Energy, we continue to excel at our fundamental commitment – and our innovative Balanced Solution strategy is the reason.



A STRONG EMPHASIS ON ENERGY EFFICIENCY. We are developing a bold new role for energy efficiency – one that benefits our customers, the environment and our business. In the past, energy efficiency and financial success were often seen as incompatible for an electric utility. But through thoughtful, consensus-based strategies, we're making energy efficiency an important and viable component of today's energy solutions. In Florida, we continued working with the governor and other key leaders to further some of the country's most advanced thinking in energy efficiency, introducing 39 new programs in 2007. In North Carolina, we are aggressively expanding our portfolio of energy-efficiency programs. Our goal is to double the 1,000 megawatts currently being saved, an amount equivalent to the capacity of more than six combustion-turbine power plants.

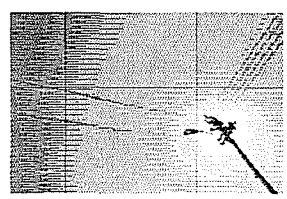
PARTNERING WITH CUSTOMERS. Today's customers are increasingly concerned about their energy spending and eager for actionable information and resources. In 2007, we launched a dynamic communications platform, *Save The Watts*,[SM] which has engaged and motivated thousands of customers. This program uses a variety of media, including television, print and the Web, to raise customer awareness of energy-saving options and resources. This collaborative relationship with customers is a critical component of operational excellence in today's landscape. And it's the foundation upon which we build constructive regulatory and public policy so we can continue excelling at the fundamentals far into the future.

Meet our innovative "spokes-bulb," Save The Watts *guy. He's on TV, the radio, even the Web, helping customers make smart energy choices.*



We're looking at the latest advances, including smart thermostats, to help our customers make better energy choices.

Throughout our service areas, we've been partnering with The Home Depot to raise awareness of new energy-saving options and offer CFLs at reduced prices.

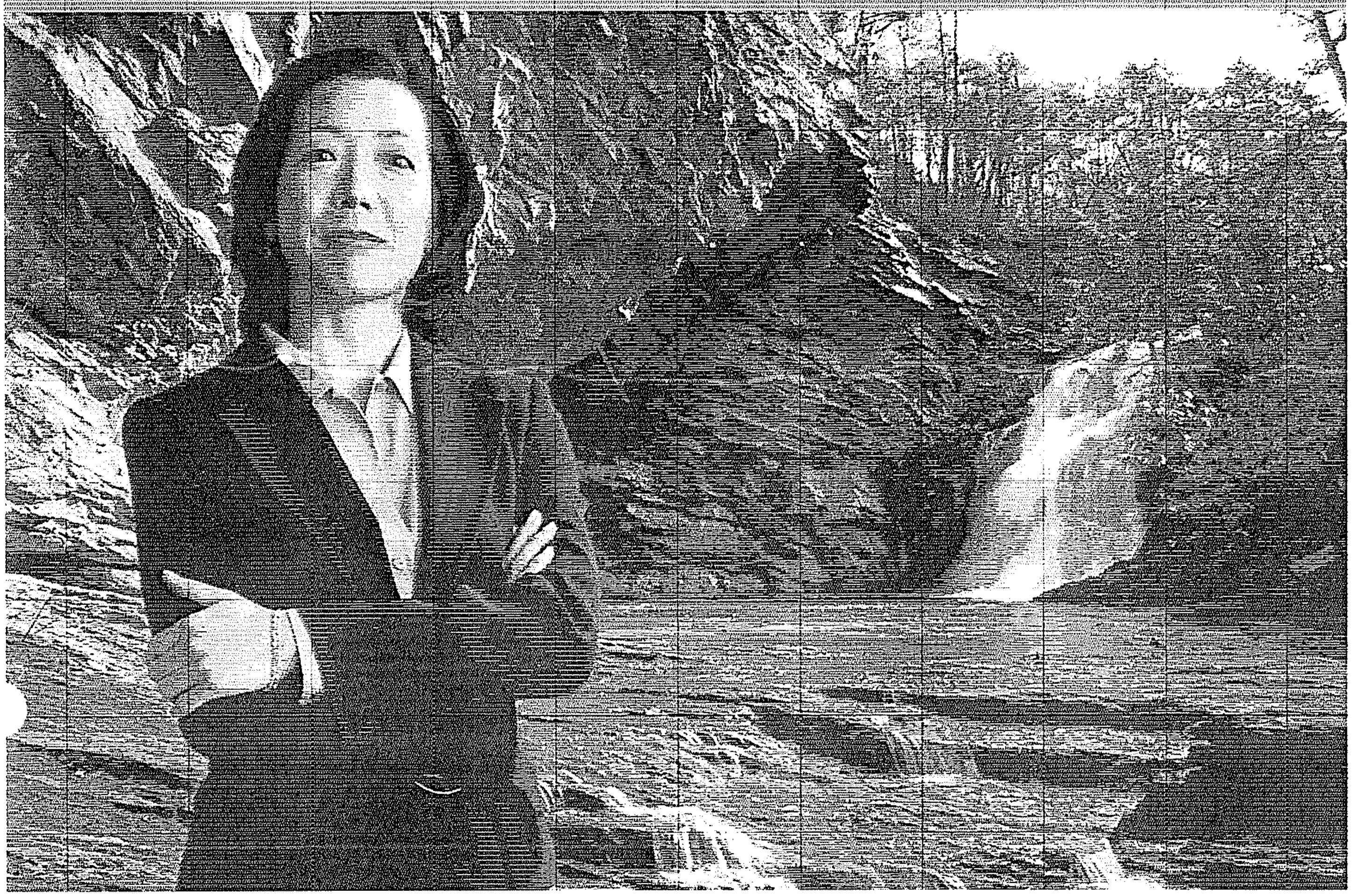


We're investing in new technologies like SmartGrid that will make our distribution system more efficient and effective for our customers.

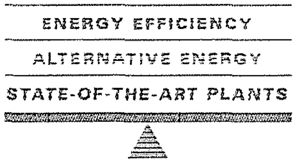
LOOKING AT ALTERNATIVE ENERGY IN A NEW LIGHT.

Tomorrow's energy breakthroughs are being developed today. It's exciting to be a part of advancing the policies that will make them more successful.

—Caroline Choi
Director, Energy Policy and Strategy
Progress Energy

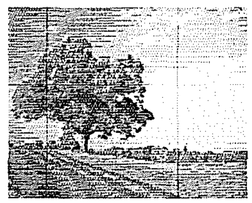


DEVELOPING VIABLE ALTERNATIVES. The second component of our Balanced Solution strategy is increased support for alternative energy. By working collaboratively with all stakeholders, from scientists to entrepreneurs, we are developing exciting and feasible alternative energy options – options that make sense for the environment and our bottom line.

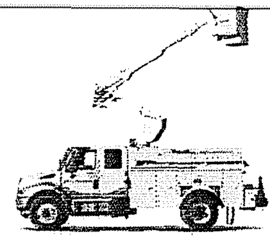


PURSUING NEW TECHNOLOGIES, NEW OPTIONS. Progress Energy is committed to increasing the proportion of renewables in our generation portfolio to help offset the need for new power plants, reduce greenhouse gas emissions and further the development of reliable and affordable alternative energy options for the future. In 2007, we issued a request for proposals, seeking viable, cost-effective renewable energy projects. Some of the options we're considering include solar photovoltaic, hydrogen, hydropower, geothermal, landfill methane gas and biomass such as poultry or hog waste. In the Carolinas, we are buying up to 1 million megawatt hours of renewable energy from various sources – equivalent to the annual needs of about 70,000 households. In Florida, we have invested in several new options, including three promising biomass projects from which we expect to buy 267 megawatts of electricity over 20 years.

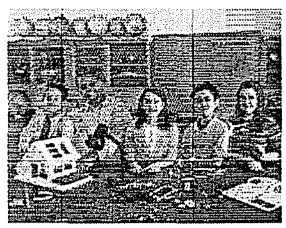
WORKING WITH OUR CUSTOMERS. Many of today's customers want tangible ways to support environmentally friendly solutions. In Florida, we recently added an incentive for solar water heating to our popular *EnergyWise*℠ program. Customers can save up to 85 percent on their water heating costs while reducing electrical demand and eliminating more than 25,000 pounds of carbon dioxide emissions over 20 years. Renewable energy sources such as this are a critical part of how we're meeting the new expectations of today's customers and securing a stronger energy future for us all.



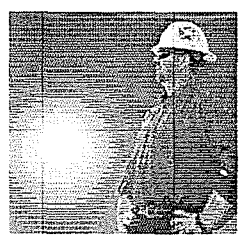
In 2007, Progress Energy was named to the Dow Jones Sustainability Index for the third straight year.



Progress Energy is taking our alternative energy message to the streets with hybrid bucket trucks and other fuel-efficient, low-emissions vehicles



We're supporting tomorrow's energy leaders today with energy education grants and our new SolarWise for Schools *program*

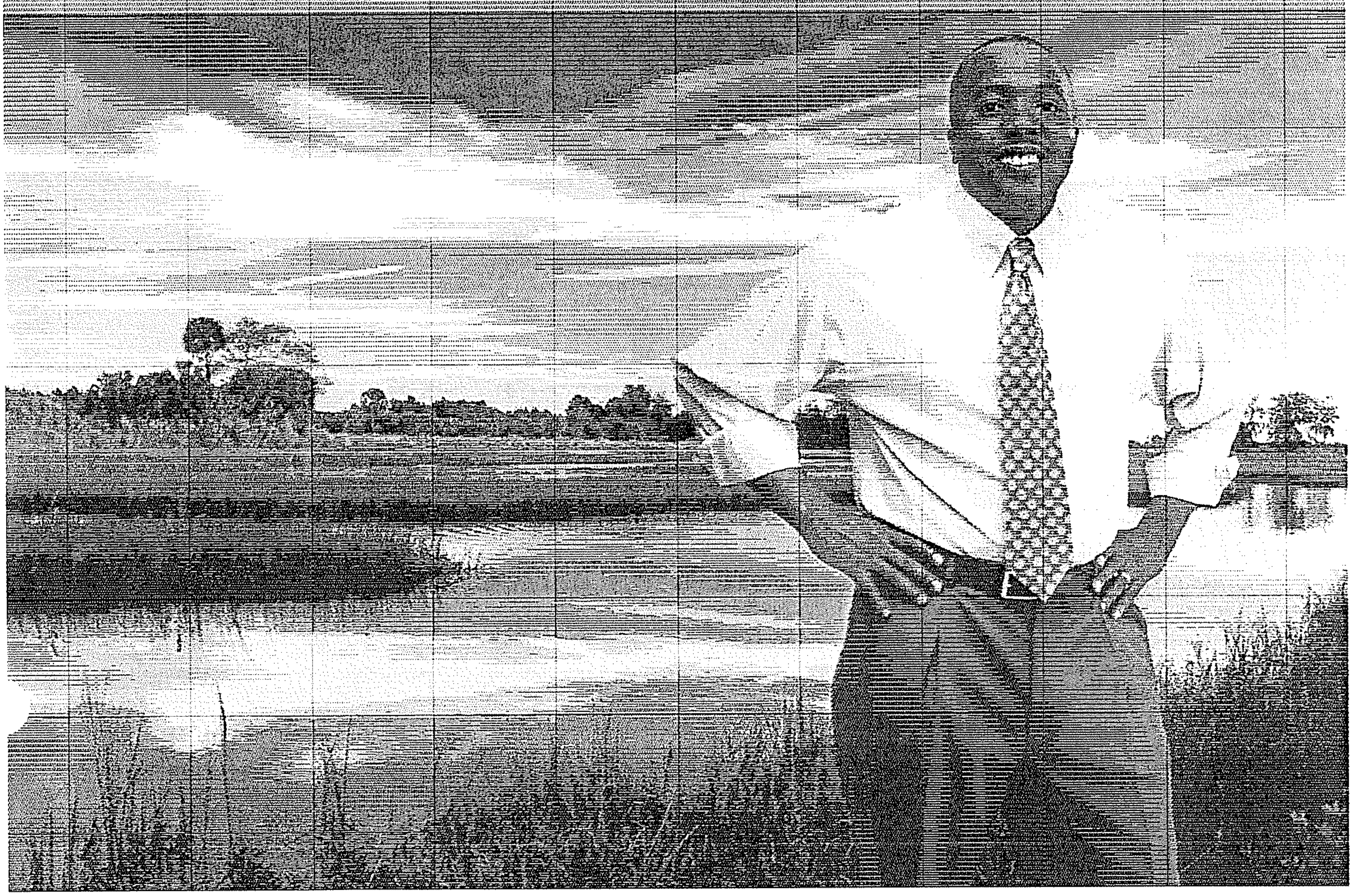


Supporting alternative energy is one of the smartest, most sustainable ways to continue delivering clean, reliable, affordable power today – and tomorrow.

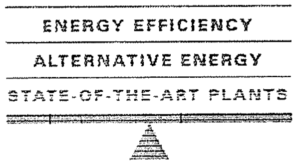
LOOKING AT POWER GENERATION IN A NEW LIGHT.

Like the parts of an intricate, efficient machine, the people at our generating plants work together to ensure safe and reliable operations.

— Rufus Jackson
Plant Manager, Anclote
Progress Energy Florida

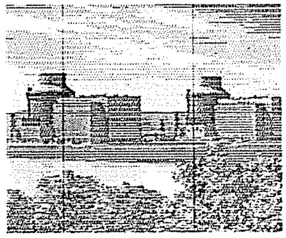


A RELIABLE COMBINATION. Every part of our Balanced Solution must work together. For our company to continue delivering clean, reliable, affordable power, we must combine energy efficiency and alternative energy with proven sources of large-scale power generation that are safe, cost-efficient and environmentally responsible.

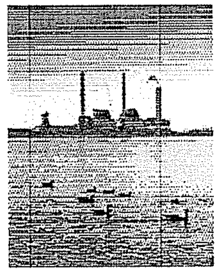


UPGRADING EXISTING PLANTS. We have a long history of operational excellence, and we continue to invest in our plants to maintain that record and at the same time address growing environmental concerns and volatility in fuel pricing and availability. We have installed "scrubber" technology on four coal-fired units, reducing emissions and making them among the cleanest in the country. And we are applying lessons learned from the highly successful Brunswick Nuclear Plant uprate, the first in the country to achieve 120 percent of its original rated capacity, to bring similar improvements in efficiency across our generation fleet.

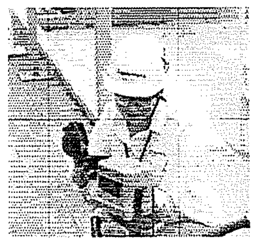
STATE-OF-THE-ART NUCLEAR GENERATION. Today we face several new energy realities: growing population and energy demand, the need to reduce greenhouse gas emissions and address global climate change, and concerns over dependence on fossil fuel. At Progress Energy, we believe strongly that new nuclear is a good option for addressing these issues. We have chosen two sites (Levy County, Fla., and the Harris Plant in North Carolina) as our preferred locations if the decision to build new nuclear plants is made. And we are working closely with our communities as we refine our future plans. Having completed our strategy of divesting noncore assets, we are confident that if we do move forward, we will have the focus and the resources to bring these large and complex projects to a safe, timely and well-managed conclusion.



We're using the latest technology to improve both the way we generate power and the way we transmit it.



State-of-the-art investments are helping us reduce emissions and increase efficiency throughout our fleet of power plants.



Advanced technology requires skilled workers. Our Power Careers Program prepares workers for the challenges ahead.

We are working collaboratively with all stakeholders through groups like the Community Energy Advisory Council (CEAC) in the Carolinas Western Region.

WORKING TOGETHER FOR A BRIGHT FUTURE.

At Progress Energy, we are more than 10,000 people with one mission: to deliver the most responsible, affordable and innovative solutions for today's changing energy landscape. Together we have streamlined and centered our business so each of us can concentrate on what we know and do best: the regulated electric utility business. We are reaching out across the company and throughout our communities, building collaborative solutions to the benefit of all stakeholders. And every day, in everything we do, we are looking at power in a new light – seeking out the smartest, most innovative ways to continue our track record of operational excellence in the face of today's changing energy needs. The result is increasing value for our shareholders, better service for our customers and communities – and a strong, sustainable future for all of us.

Strong leadership helps us excel.

THE RIGHT BALANCE FOR SUCCESS

On track to be the country's largest "pure play" regulated electric utility

Balanced Solution for the changing energy landscape

Growing customer base and investment opportunities

Motivated employees dedicated to operational excellence

Constructive community relations and regulatory environments

Committed to our communities – $10.8 million invested in 2007

Boosted economic development, bringing [illegible] million [illegible] to our communities

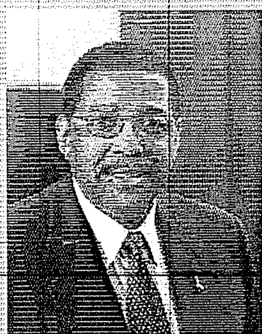
[illegible]

[illegible]

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.



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; Operations and Nuclear Oversight.

David L. Burner
Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services)
Darby, Mont.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

Richard L. Daugherty
Formerly Executive Director, NCSU Research Corp., Vice President, IBM PC Company and Senior State Executive, IBM Corp.
Raleigh, N.C.

Elected to the board in 1992 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.

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) and President and Chief Executive Officer, Steuben Glass
Corning, N.Y.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; 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 value-added services and technology to the nuclear generation industry worldwide)
Lynchburg, Va.

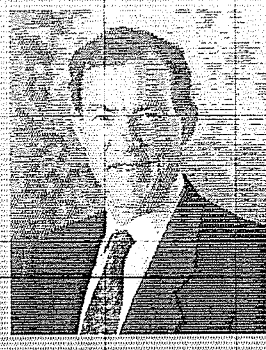
Elected to the board in 2007 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

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; Operations and Nuclear Oversight (Chair); Organization and Compensation.

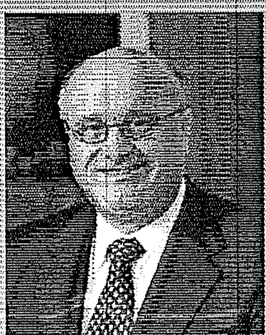
Robert W. Jones
Senior Advisor, Morgan Stanley (global provider of financial services to companies, governments and investors)
Bedford, N.Y.

Elected to the board in 2007 and sits on the following committees: Finance; Organization and Compensation.



W. Steven Jones
Dean and Professor of Management of Kenan-Flagler Business School at the University of North Carolina at Chapel Hill
Chapel Hill, N.C.

Elected to the board in 2005 and sits on the following committees: Operations and Nuclear Oversight; Organization and Compensation.



Carlos A. Saladrigas
Chairman, Premier American Bank and retired Chief Executive Officer, ADP TotalSource
Miami, Fla.

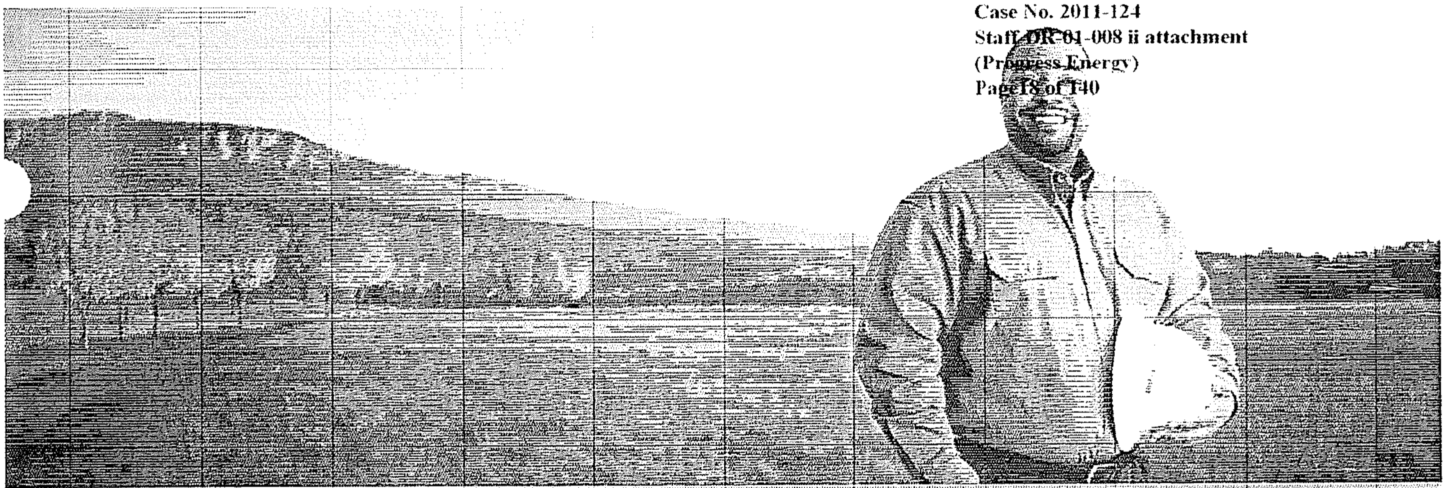
Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.

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; Finance.

Alfred C. Tollison, Jr.
Retired Chairman and Chief Executive Officer, Institute of Nuclear Power Operations (INPO is a nuclear industry-sponsored nonprofit organization)
Marietta, Ga.

Elected to the board in 2006 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.



Jeffrey Jenkins, first class Line and Service technician, Progress Energy Carolinas

Progress Energy achieved full compliance with the applicable internal control requirements in connection with its 2007 financial reporting processes.

RESPONSIBILITIES OF BOARD COMMITTEES

AUDIT AND CORPORATE PERFORMANCE COMMITTEE

This committee reviews the annual and quarterly financial results of the company and the various periodic reports the company files with the Securities and Exchange Commission. It is responsible for retaining the company's external auditors, overseeing and monitoring the auditors' activities and pre-approving all external audit and non-audit services and fees. This committee also oversees the activities of the internal audit department and the Corporate Ethics Program.

CORPORATE GOVERNANCE COMMITTEE

This committee is responsible for making recommendations on the structure, charter, practices and policies of the board, including amendments to the articles of incorporation and bylaws. The committee ensures that processes are in place for annual CEO performance appraisal, reviews of succession planning and management development. It also recommends the process for the annual assessment of board performance and criteria for board membership. In addition, it proposes nominees to the board.

FINANCE COMMITTEE

This committee reviews and oversees the company's financial policies and planning and the company's pension funds. It monitors the company's financial position, reviews the company's strategic investments and financing options and recommends changes in the company's dividend policy.

OPERATIONS AND NUCLEAR OVERSIGHT COMMITTEE

This committee reviews the company's load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading, term marketing and other company operations with a particular emphasis on nuclear operations. The committee ensures company policies, procedures and practices relative to environmental protection and safety-related issues are sufficient to achieve and maintain compliance with applicable laws and regulations, and advises and makes recommendations to the board regarding these matters.

ORGANIZATION AND COMPENSATION COMMITTEE

This committee reviews personnel policies and procedures for consistency with governmental rules and regulations and ensures that the company attracts and retains competent, talented employees. The committee reviews all executive-development and management-succession plans, evaluates CEO performance and makes senior executive compensation decisions.

EXECUTIVE AND SENIOR OFFICERS

William D. Johnson
Chairman, President and Chief Executive Officer

Peter M. Scott III
Executive Vice President and Chief Financial Officer
Progress Energy, Inc.
President and Chief Executive Officer
Progress Energy Service Company, LLC

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

Jeffrey J. Lyash
President and Chief Executive Officer
Progress Energy Florida, 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.

John R. McArthur
Senior Vice President – Corporate Relations
General Counsel and Secretary

Mark F. Mulhern
Senior Vice President – Finance
Progress Energy Service Company, LLC

James Scarola
Senior Vice President and
Chief Nuclear Officer – Nuclear Generation
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, estimated capital requirements through the year 2010 and future financing plans; and d) "Other Matters" about our synthetic fuels tax credits, the effects of new environmental regulations, nuclear decommissioning costs and changes in the regulatory environment.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the Energy Policy Act of 2005 (EPACT); the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the impact on our facilities and businesses from a terrorist attack, weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; our ability to control costs, including operations and maintenance (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the ability to successfully access capital markets on favorable terms; the impact that increases in leverage may have on us; our ability to maintain our current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); the investment performance of our nuclear decommissioning trust funds and assets of pension and benefit plans; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. 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 United States Securities and Exchange Commission (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 it 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 and Progress Energy Florida, as the "Utilities." MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements.

INTRODUCTION

Our reportable business segments and their primary operations include:

- Progress Energy Carolinas (PEC) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina; and
- Progress Energy Florida (PEF) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida.

The "Corporate and Other" segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses that do not separately meet the quantitative requirements as a separate business segment.

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. Our two electric utilities operate in regulated retail utility markets in the southeastern United States and have access to robust wholesale markets in the eastern United States, which we believe positions us well for long-term growth. We are focused on the following key priorities:

- consistently excelling in the daily fundamentals of our utility business, including safely and reliably generating and delivering power to our customers;
- successfully implementing our balanced solution to responsibly address demand growth and climate change;
- maintaining constructive regulatory relations; and
- achieving our financial objectives year after year.

The Utilities operate in the southeastern United States, one of the fastest-growing regions of the country, and had a net increase of approximately 51,000 customers over the past year. Despite our anticipated customer growth, the Utilities are subject to economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets. Under normal weather conditions, we anticipate approximately 1.5 percent to 2.0 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.0 percent to 2.5 percent annual retail kWh sales growth at PEF in 2008. The Utilities seek a mix of 80 percent retail and 20 percent wholesale. The Utilities are focused on maintaining their regulated wholesale business through targeted contract renewals and origination opportunities.

We are implementing a comprehensive plan to meet the anticipated demand in the Utilities' service territories by focusing on energy efficiency, alternative energy and state-of-the-art power generation. First, we are enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. Recent legislation in North Carolina and Florida provides recovery for eligible costs of these programs. Second, we are pursuing renewable and alternative energy to increase the proportion of renewable and alternative energy sources in our generation portfolio. Recent legislation in North Carolina established a minimum renewable energy portfolio standard beginning in 2012. Executive orders issued by the governor of Florida address the reduction of greenhouse gas emissions and may lead to renewable energy standards in Florida. The Utilities have requested proposals for alternative energy sources, and options being considered include conversion of waste (such as wood, scrap tires and landfill gas) to energy, biomass as well as investments in solar and fuel cell programs. Third, we are evaluating new generation and fleet upgrades as we estimate that we will require new baseload generation facilities at both PEC and PEF toward the end of the next decade. We are evaluating the best available options for new generation, including advanced design nuclear technology, gas-fired combined cycle and combustion turbines, and modernization of existing coal plants to use clean coal technology. The considerations that will factor into this decision include, but are not limited to, construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing.

On February 19, 2008, PEC filed its combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors at the Shearon Harris Nuclear Plant (Harris). We anticipate filing a COL application in 2008 to potentially construct new nuclear plants in Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. If we decide to pursue nuclear expansion, favorable changes in the regulatory and construction processes have evolved in recent years, including standardized design, detailed design before construction, COL to build and operate, streamlined regulatory approval process, annual prudence reviews and cost-recovery mechanisms for pre-construction and financing costs. State regulatory processes are specific to each jurisdiction. Also, nuclear generation has recently gained greater public support as a reliable energy source that does not emit greenhouse gases. See "Other Matters – Nuclear Matters" for additional information.

We are subject to significant air quality regulations passed in 2005 by the United States Environmental Protection Agency (EPA) that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR) and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule [CAMR]). Additionally, at PEC's coal-fired facilities in North Carolina, we are subject to the North Carolina Clean Smokestacks Act enacted in 2002 (Clean Smokestacks Act). Including estimated costs for CAIR, CAVR, mercury regulation and the Clean Smokestacks Act, we currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or pass-through clauses, could be in excess of $700 million at PEC and $1.9 billion at PEF through 2018, which corresponds to the latest emission reduction deadline. In addition, growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other greenhouse gases. 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.

The Utilities successfully resolved key state regulatory issues in 2007, including retail fuel recovery filings in all jurisdictions. PEF also received Federal Energy Regulatory Commission (FERC) approval of its revised Open Access Transmission Tariff (OATT), including a settlement agreement with major transmission customers. In addition to Florida energy legislation enacted in 2006 that included cost-recovery mechanisms supportive of nuclear expansion, North Carolina and South Carolina both enacted energy legislation in 2007. North Carolina's comprehensive energy bill included provisions for expanding the traditional fuel clause, renewable energy portfolio standards, recovery of qualified DSM and energy-efficiency programs and cost recovery during baseload generation construction. Key elements of South Carolina's energy law included expansion of the annual fuel clause and recovery mechanisms and streamlined regulatory processes supportive of nuclear expansion. As part of the Clean Smokestacks Act, PEC operated under a base rate freeze in North Carolina through 2007. Subsequent to 2007, PEC's current North Carolina base rates are continuing subject to traditional cost-based rate regulation. As a result of its 2005 base rate proceeding, PEF's base rate settlement extends through 2009. See "Other Matters – Regulatory Environment" and Note 7 for further information.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 20 consecutive years, and 32 of the last 33 years. We plan to continue our efforts to enhance balance sheet strength and flexibility so that we are positioned to accommodate the significant future growth expected at the Utilities. As of the end of 2007, our debt to total capitalization ratio was 53.3 percent. Our targeted debt to total capitalization ratio is 55 percent.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities' earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies, cost controls, and the timing of recovery of fuel costs and storm damage. The Utilities contributed $813 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2007. Partially offsetting the Utilities' segment profit contribution were losses of $120 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

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

We expect total capital expenditures (including expenditures for environmental compliance) for 2008, 2009 and 2010 to be approximately $2.8 billion, $2.9 billion and $2.8 billion, respectively. Subject to regulatory approval, applicable capital investments to support load growth and comply with environmental regulations increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized, and create the basis for long-term earnings growth in the Utilities.

We expect to fund our business plans and new generation through operating cash flows and a combination of long-term debt, preferred stock and common equity, all of which are dependent on our ability to successfully access capital markets. We may also pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

Our synthetic fuels operations have historically provided significant net earnings driven by the Section 29/45K tax credit program, which expired at the end of 2007. In accordance with our decision to permanently cease production of synthetic fuels, we abandoned our majority-owned facilities in the fourth quarter of 2007. The operations of our synthetic fuels businesses were reclassified to discontinued operations in 2007. However, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred Section 29/45K tax credits generated through December 31, 2007, but not yet utilized, are ultimately utilized. At December 31, 2007, the amount of these deferred tax credits carried forward was $830 million. See "Other Matters – Synthetic Fuels Tax Credits" below and Note 22D for additional information on our synthetic fuels tax credits and other matters.

As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, the majority of our nonregulated business operations have been divested or are in the process of being divested. These operations have been classified as discontinued operations in the accompanying financial statements. Consequently, the composition of other continuing segments has been impacted by these divestitures.

RESULTS OF OPERATIONS

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

Overview

FOR 2007 AS COMPARED TO 2006 AND 2006 AS COMPARED TO 2005

For the year ended December 31, 2007, our net income was $504 million or $1.97 per share compared to $571 million or $2.28 per share for the same period in 2006. For the year ended December 31, 2007, our income from continuing operations was $693 million compared to $551 million for the same period in 2006. The increase in income from continuing operations as compared to prior year was due primarily to:

- lower Clean Smokestacks Act amortization expense at PEC;
- lower interest expense at the Parent due to reducing debt in late 2006;
- the cost incurred to redeem debt at the Parent in 2006;
- favorable weather at PEC;
- lower allocations of corporate overhead to continuing operations as a result of the 2006 divestitures;
- unrealized losses recorded on contingent value obligations (CVOs) during 2006;
- favorable allowance for funds used during construction (AFUDC) equity at the Utilities;
- favorable growth and usage at the Utilities; and
- higher wholesale sales at PEF.

Partially offsetting these items were:

- higher O&M expenses at the Utilities primarily due to higher outage and maintenance costs and higher employee benefits;
- additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generation assets (See Note 7B);

- higher interest expense at PEF;
- the impact of the 2006 gain on sale of Level 3 Communications, Inc (Level 3) stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- higher other operating expenses due to disallowed fuel costs at PEF

For the year ended December 31, 2006, our net income was $571 million or $2.28 per share compared to $697 million or $2.82 per share for the same period in 2005. For the year ended December 31, 2006, our income from continuing operations was $551 million compared to $523 million for the same period in 2005. The increase in income from continuing operations as compared to prior year was due primarily to:

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

Partially offsetting these items were:

- unfavorable weather at the Utilities;
- the cost incurred to redeem debt at the Parent;
- unrealized losses recorded on CVOs;
- increased nuclear outage expenses at PEC; and
- the prior year gain on the sale of PEF's utility distribution assets serving the City of Winter Park, Fla. (Winter Park).

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

(in millions)	2007	Change	2006	Change	2005
PEC	**$498**	$44	$454	$(36)	$490
PEF	**315**	(11)	326	68	258
Total segment profit	**813**	33	780	32	748
Corporate and Other	**(120)**	109	(229)	(4)	(225)
Total income from continuing operations	**693**	142	551	28	523
Discontinued operations, net of tax	**(189)**	(209)	20	(153)	173
Cumulative effect of change in accounting principle, net of tax	**–**	–	–	(1)	1
Net income	**$504**	$(67)	$571	$(126)	$697

COST-MANAGEMENT INITIATIVE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, of which $5 million has been reclassified to discontinued operations. We did not incur similar charges during 2007 or 2006. The severance and postretirement charges are primarily included in O&M expense on the Consolidated Statements of Income and will be paid over time.

Progress Energy Carolinas

PEC contributed segment profits of $498 million, $454 million and $490 million in 2007, 2006 and 2005, respectively. The increase in profits for 2007 as compared to 2006 is primarily due to lower Clean Smokestacks Act amortization, the favorable impact of weather and favorable retail customer growth and usage, partially offset by higher O&M expenses related to plant outage and maintenance costs and employee benefit costs and additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generating assets.

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

The revenue tables below present the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel is defined as total electric revenues less fuel revenues. We consider revenues excluding fuel a useful measure to evaluate PEC's electric operations because fuel revenues primarily represent the recovery of fuel and a portion of purchased power expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with accounting principles generally accepted in the United States of America (GAAP). However, revenues excluding fuel are not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report

REVENUES

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

(in millions)					
Customer Class	**2007**	% Change	2006	% Change	2005
Residential	**$1,613**	10.3	$1,462	2.8	$1,422
Commercial	**1,107**	10.3	1,004	6.8	940
Industrial	**716**	0.7	711	3.9	684
Governmental	**98**	7.7	91	4.6	87
Total retail revenues	**3,534**	8.1	3,268	4.3	3,133
Wholesale	**754**	4.7	720	(5.1)	759
Unbilled	**–**	–	(1)	–	4
Miscellaneous	**96**	(2.0)	98	4.3	94
Total electric revenues	**4,384**	7.3	4,085	2.4	3,990
Less: Fuel revenues	**(1,524)**	–	(1,314)	–	(1,186)
Revenues excluding fuel	**$2,860**	3.2	$2,771	(1.2)	$2,804

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

(in thousands of MWh)					
Customer Class	**2007**	% Change	2006	% Change	2005
Residential	**17,200**	5.8	16,259	(2.4)	16,664
Commercial	**14,032**	5.0	13,358	0.3	13,313
Industrial	**11,901**	(4.0)	12,393	(2.5)	12,716
Governmental	**1,438**	1.3	1,419	0.6	1,410
Total retail energy sales	**44,571**	2.6	43,429	(1.5)	44,103
Wholesale	**15,309**	5.0	14,584	(6.9)	15,673
Unbilled	**(55)**	–	(137)	–	(235)
Total MWh sales	**59,825**	3.4	57,876	(2.8)	59,541

PEC's revenues, excluding fuel revenues of $1.524 billion and $1.314 billion for 2007 and 2006, respectively, increased $89 million. The increase in revenues was due primarily to the $57 million favorable impact of weather and a $22 million favorable impact of retail customer growth and usage. Weather had a favorable impact as cooling degree days were 20 percent higher than 2006. Cooling degree days were 16 percent higher than normal. The favorable retail customer growth and usage was driven by an approximate increase in the average number of customers of 28,000 as of December 31, 2007, compared to December 31, 2006.

Industrial electric energy sales decreased in 2007 compared to 2006 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a downturn in the lumber and building materials segment as a result of declines in residential construction. The increase in industrial revenues for 2007 compared to 2006 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

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

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

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $1.683 billion for 2007, which represents a $176 million increase compared to 2006. Fuel used in electric generation increased $208 million to $1.381 billion compared to 2006. This increase is primarily due to a $156 million increase in fuel used in generation and a $54 million increase in deferred fuel expense. Fuel used in generation increased primarily due to a change in generation mix as the percentage of generation supplied by natural gas increased in response to plant outages and higher system requirements driven by favorable weather. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Purchased power expenses decreased $32 million to $302 million compared to prior year. The decrease in purchased power is due to lower cogeneration as a result of contract changes with one of PEC's co-generators.

Fuel and purchased power expenses were $1.507 billion for 2006, which represents a $117 million increase compared to 2005. Fuel used in electric generation increased $137 million to $1.173 billion compared to 2005. This increase is due to a $141 million increase in deferred fuel expense partially offset by a $5 million decrease in fuel used in generation. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Fuel used in generation decreased primarily due to lower system requirements. Purchased power expenses decreased $20 million to $334 million compared to prior year. The decrease in purchased power is due primarily to a change in volume as a result of lower system requirements.

Operation and Maintenance

O&M expenses were $1.024 billion for 2007, which represents a $94 million increase compared to 2006. This increase is driven primarily by the $49 million higher plant outage and maintenance costs (partially due to three nuclear outages in the current year compared to only two in the prior year) and $29 million due to higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008.

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

Depreciation and Amortization

Depreciation and amortization expense was $519 million for 2007, which represents a $52 million decrease compared to 2006. This decrease is primarily attributable to a $106 million decrease in the Clean Smokestacks Act amortization, partially offset by $37 million additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets (See Note 7B), $11 million charge to reduce PEC's GridSouth Transco, LLC (GridSouth) regional transmission organization (RTO) development costs (See Note 7D) and the $7 million impact of depreciable asset base increases. We recorded $34 million of Clean Smokestacks Act amortization during 2007 compared to $140 million in 2006 (See Note 7B). We recorded $37 million of additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets during 2007 compared to none in 2006.

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

Taxes Other than on Income

Taxes other than on income were $192 million, $191 million and $178 million for 2007, 2006 and 2005, respectively. The $13 million increase in 2006 compared to 2005 is primarily due to a $7 million increase in property taxes and a $6 million increase in gross receipts taxes related to higher revenue. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expenses consisted of gains of $2 million and $10 million in 2007 and 2005, respectively, primarily due to land sales. There were no gains from land sales in 2006.

Total Other Income (Expense)

Total other income (expense) was $37 million of income for 2007, which represents a $13 million decrease compared to 2006. This decrease is primarily due to the 2006 reclassification of $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). This decrease is partially offset by $6 million favorable AFUDC equity related to costs associated with certain large construction projects.

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

Total Interest Charges, Net

Total interest charges, net were $210 million for 2007, which represents a $5 million decrease compared to 2006. This decrease is primarily due to the $5 million impact of a decrease in average long-term debt and $3 million favorable AFUDC debt related to costs associated with certain large construction projects, partially offset by $2 million higher interest related to higher variable rates on pollution control obligations.

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

Income Tax Expense

Income tax expense was $295 million, $265 million and $239 million in 2007, 2006 and 2005, respectively. The $30 million income tax expense increase in 2007 compared to 2006 is primarily due to the impact of higher pre-tax income. The $26 million income tax expense increase in 2006 compared to 2005 is primarily due to the allocation of $23 million of the Parent's tax benefit not related to acquisition interest expense in 2005 that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

Progress Energy Florida

PEF contributed segment profits of $315 million, $326 million and $258 million in 2007, 2006 and 2005, respectively. The decrease in profits for 2007 as compared to 2006 is primarily due to higher O&M expenses related to plant outage and maintenance costs and employee benefit costs, higher interest expense, higher other operating expenses and higher depreciation and amortization expense excluding recoverable storm amortization, partially offset by favorable AFUDC and higher wholesale sales.

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

The revenue tables below present the total amount and percentage change of revenues excluding fuel and other pass-through revenues. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, revenues excluding fuel and other pass-through revenues are not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

(in millions)					
Customer Class	2007	% Change	2006	% Change	2005
Residential	$2,363	0.1	$2,361	18.0	$2,001
Commercial	1,153	0.1	1,152	21.5	948
Industrial	318	(8.1)	346	21.8	284
Governmental	304	1.0	301	24.4	242
Revenue sharing refund	–	–	1	–	(1)
Total retail revenues	4,138	(0.6)	4,161	19.8	3,474
Wholesale	434	36.1	319	(7.3)	344
Unbilled	4	–	(5)	–	(6)
Miscellaneous	173	5.5	164	14.7	143
Total electric revenues	4,749	2.4	4,639	17.3	3,955
Less: Fuel and other pass-through revenues	(3,109)	–	(3,038)	–	(2,385)
Revenues excluding fuel and other pass-through revenues	$1,640	2.4	$1,601	2.0	$1,570

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

(in thousands of MWh)					
Customer Class	2007	% Change	2006	% Change	2005
Residential	19,912	(0.5)	20,021	0.6	19,894
Commercial	12,183	1.7	11,975	0.3	11,945
Industrial	3,820	(8.2)	4,160	0.5	4,140
Governmental	3,367	2.8	3,276	2.4	3,198
Total retail energy sales	39,282	(0.4)	39,432	0.7	39,177
Wholesale	5,930	30.8	4,533	(17.0)	5,464
Unbilled	88	–	(234)	–	(205)
Total MWh sales	45,300	3.6	43,731	(1.6)	44,436

PEF's revenues, excluding fuel and other pass-through revenues of $3.109 billion and $3.038 billion for 2007 and 2006, respectively, increased $39 million. The increase in revenues is primarily due to increased wholesale revenues, favorable retail customer growth and usage and other miscellaneous service revenues. Wholesale revenues increased $29 million primarily due to the $21 million impact of increased capacity under contract with a major customer. The favorable retail customer growth and usage impact of $7 million was driven by an approximate average net increase in the number of customers of 23,000 as of December 31, 2007, compared to December 31, 2006, partially offset by lower average usage per customer. Other miscellaneous service revenues increased primarily due to increased electric property rental revenues of $6 million.

Industrial electric energy revenues and sales decreased in 2007 compared to 2006 primarily due to a change in the terms of an agreement with a major customer.

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

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $2.646 billion in 2007, which represents a $45 million increase compared to 2006. Purchased power expense increased $116 million to $882 million compared to 2006. This increase is primarily due to a $123 million increase in current year purchased power costs partially offset by a $6 million decrease in the recovery of deferred capacity costs. The increased current year purchased power costs are a result of higher interchange purchases of $87 million and higher capacity costs of $43 million primarily due to new contracts. Fuel used in electric generation decreased $71 million to $1.764 billion due to a $323 million decrease in deferred fuel expense partially offset by a $252 million increase in current year fuel costs due primarily to an increase in oil and natural gas prices. Deferred fuel expenses were higher in 2006 primarily due to the collection of fuel costs from customers that had been previously under-recovered.

Fuel and purchased power expenses were $2.601 billion in 2006, which represents a $584 million increase compared to 2005. Fuel used in electric generation increased $512 million due to a $552 million increase in deferred fuel expense resulting from an increase in the fuel recovery rates on January 1, 2006, as a result of fuel costs from customers that had been previously under-recovered. This was partially offset by a $41 million decrease in current year fuel costs due primarily to lower system requirements. Purchased power expense increased $72 million primarily due to a $48 million increase in current year purchased power costs resulting from higher market prices and a $23 million increase in the recovery of deferred capacity costs.

Operation and Maintenance

O&M expenses were $834 million in 2007, which represents a $150 million increase compared to 2006. The increase is primarily due to $46 million related to an increase in storm damage reserves from the one-year extension of the storm surcharge, which began August 2007 (See Note 7C) and $40 million related to higher environmental cost recovery (ECRC) and energy conservation cost recovery (ECCR) costs. Additionally, the increase is due to $27 million higher plant outage and maintenance costs and $12 million higher employee benefit costs. The higher employee benefit costs are primarily due to current year changes in equity compensation plans and higher relative employee incentive goal achievement in 2007 compared to 2006. We do not expect the increase related to changes in equity compensation plans to continue in 2008. The ECRC, ECCR and storm damage reserve expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings.

O&M expenses were $684 million in 2006, which represents a $168 million decrease compared to 2005. The decrease is primarily due to a $102 million impact of postretirement and severance costs in 2005, $24 million of lower ECRC expenses due to a decrease in emission allowances and lower recovery rates, $17 million related to the 2005 write-off of unrecoverable storm restoration costs (See Note 7C), a $9 million decrease in nuclear outage costs and the $6 million impact related to the 2005 write-off of GridFlorida RTO startup costs that were previously recovered in revenues.

Depreciation and Amortization

Depreciation and amortization expense was $366 million for 2007, which represents a decrease of $38 million compared to 2006, primarily due to $47 million lower amortization of storm restoration costs and $5 million lower software and franchise amortization, partially offset by the $13 million impact primarily related to depreciable asset base increases and a $7 million write-off of leasehold improvements, primarily related to vacated office space. Storm restoration costs, which were fully amortized in 2007, were recovered through the storm recovery surcharge and, therefore, have no material impact on earnings (See Note 7C).

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

Taxes Other than on Income

Taxes other than on income were $309 million for 2007 and 2006, and $279 million for 2005. The $30 million increase in 2006 compared to 2005 is primarily due to $18 million of higher gross receipts taxes and $14 million of higher franchise taxes, related to an increase in revenues, partially offset by lower payroll taxes. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expenses were $8 million in 2007 compared to a gain of $2 million in 2006. The $10 million difference is primarily due to the $12 million impact of a Florida Public Service Commission (FPSC) order requiring PEF to refund disallowed fuel costs to its ratepayers (See Note 7C).

Other operating expenses were a gain of $2 million in 2006 compared to a gain of $26 million in 2005. The decrease in the gain for 2006 compared to 2005 is primarily due to the $24 million gain on the sale of the utility distribution assets serving Winter Park recorded in 2005 (See Note 7C).

Total Other Income

Total other income was $48 million for 2007, which represents a $20 million increase compared to 2006. This increase is primarily due to $24 million favorable AFUDC equity related to costs associated with large construction projects, partially offset by $5 million lower interest income on unrecovered storm restoration costs. We expect AFUDC equity to continue to increase in 2008, primarily due to increased spending on environmental initiatives and other large construction projects. See "Future Liquidity and Capital Resources – Capital Expenditures."

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

Total Interest Charges, Net

Total interest charges, net were $173 million in 2007, which represents an increase of $23 million compared to 2006. The increase in interest charges is primarily due to the $10 million impact of an increase in average long-term debt, the $7 million impact of interest on over-recovered fuel costs, $6 million increase in interest on income tax related items and $2 million increase related to the disallowed fuel costs (See Note 7C). These increases are partially offset by $7 million favorable AFUDC debt related to costs associated with large construction projects.

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

Income Tax Expense

Income tax expense was $144 million, $193 million and $121 million in 2007, 2006 and 2005, respectively. The $49 million income tax expense decrease in 2007 compared to 2006 is primarily due to the $23 million impact of lower pre-tax income compared to the prior year, the $14 million impact of tax adjustments and the $9 million impact of favorable AFUDC equity discussed above. The tax adjustments are primarily related to the $11 million impact of changes in income tax estimates and the $3 million favorable impact related to the closure of certain federal tax years and positions. AFUDC equity is excluded from the calculation of income tax expense. The $72 million income tax expense increase in 2006 compared to 2005 is primarily due to changes in pre-tax income. In addition, 2005 income tax expense included the allocation of $13 million of the Parent's tax benefit not related to acquisition interest expense that was suspended in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

Corporate and Other

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. Corporate and Other expense is summarized below:

(in millions)	**2007**	Change	2006	Change	2005
Other interest expense	**$(205)**	$54	$(259)	$(2)	$(257)
Contingent value obligations	**(2)**	23	(25)	(31)	6
Tax reallocation	**–**	–	–	38	(38)
Other income tax benefit	**105**	(14)	119	19	100
Other expense	**(18)**	46	(64)	(28)	(36)
Corporate and Other after-tax expense	**$(120)**	$109	$(229)	$(4)	$(225)

Other interest expense, which includes elimination entries, decreased $54 million for 2007 compared to 2006 primarily due to the $86 million impact of the $1.7 billion reduction in debt at the Parent during 2006, partially offset by a $45 million decrease in the interest allocated to discontinued operations. The decrease in interest expense allocated to discontinued operations resulted from the allocations of interest expense in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $13 million and $58 million for 2007 and 2006, respectively.

Other interest expense, which includes elimination entries, increased $2 million for 2006 compared to 2005 primarily due to a $19 million decrease in the interest allocated to discontinued operations and a decrease in the elimination of intercompany interest expense due to lower intercompany debt balances partially offset by lower interest expense due to lower debt at the Parent. The decrease in interest expense allocated to discontinued operations resulted from the full year allocations of interest expense in 2005 compared to partial year allocations of interest in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $58 million and $77 million for 2006 and 2005, respectively.

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. At December 31, 2007, 2006 and 2005, the CVOs had a fair value of approximately $34 million, $32 million and $7 million, respectively. Progress Energy recorded unrealized losses of $2 million and $25 million for 2007 and 2006, respectively, and unrealized gains of $6 million for 2005, to record the changes in fair value of the CVOs, which had average unit prices of $0.35, $0.33 and $0.07 at December 31, 2007, 2006 and 2005, respectively.

For the years ended December 31, 2007 and 2006, income tax expense was not increased by the allocation of the Parent's income tax benefits not related to acquisition interest expense to profitable subsidiaries. Due to the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), beginning in 2006 we no longer allocate the Parent income tax benefits not related to acquisition interest expense to profitable subsidiaries. Since 2002, Parent income tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a PUHCA 1935 order. For the year ended December 31, 2005, income tax expense was increased by $38 million due to the allocation of the Parent's income tax benefit.

Other income tax benefit decreased for 2007 compared to 2006 primarily due to decreased pre-tax expense at the Parent primarily as a result of the loss on early retirement of debt in 2006, partially offset by the $14 million impact related to the closure of certain federal tax years and positions (See Note 14), the $18 million impact of taxes on interest allocated to discontinued operations and the $5 million impact related to the deduction for domestic production activities. Other income tax benefit increased for 2006 compared to 2005 primarily due to increased pre-tax expense at the Parent and the $8 million impact of taxes on interest allocated to discontinued operations.

For 2007, other expense was $18 million compared to $64 million in 2006. The $46 million decrease is primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent in 2006 (See Note 12) and the $30 million decrease in the allocation of corporate overhead as a result of the divestitures completed during 2006. These decreases are partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC in 2006 (See Note 3E) and the $14 million increase in interest income on temporary investments due to proceeds from the sale of nonregulated businesses. The $28 million increase in other expense from 2005 to 2006 was primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC. In addition, other expense changed due to a $14 million increase in interest income on temporary investments due to proceeds from the sale of DeSoto County Generating Co., LLC (DeSoto), Rowan County Power, LLC (Rowan) and our natural gas drilling and production business (Gas).

Discontinued Operations

Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses to focus on the core operations of the Utilities. We divested, or announced divestitures, of multiple nonregulated businesses during 2007 and 2006. Consequently, the composition of other continuing segments has been impacted by these divestitures.

CCO OPERATIONS

CCO – Georgia Operations

On March 9, 2007, our subsidiary Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006 (See Note 3A).

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 formerly serviced by CCO (the Georgia Contracts), forward gas and power contracts, gas transportation, structured power and other contracts to a third party. This represents 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 represents the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax. We used the net proceeds from these transactions for general corporate purposes.

CCO's operations generated net losses from discontinued operations of $283 million, $57 million and $54 million in 2007, 2006 and 2005, respectively. Net losses from discontinued operations in 2007 primarily represent the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to dedesignated natural gas hedges. These hedges were dedesignated because management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet of natural gas would be fulfilled. Therefore, cash flow hedge accounting was discontinued.

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

CCO – DeSoto and Rowan Generation Facilities

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

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006. DeSoto and Rowan operations generated combined net earnings from discontinued operations of $10 million and $3 million for the years ended December 31, 2006 and 2005, respectively.

TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously reported as a component of our former Coal and Synthetic Fuels operating segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes (See Note 3B).

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code. The production and sale of these products qualified for federal income tax credits under Section 29/45K so long as certain requirements were satisfied (See "Other Matters – Synthetic Fuels Tax Credits"). On September 14, 2007, we idled production of synthetic fuels at our majority-owned fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007 and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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. In accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets," a long-lived asset is abandoned when it ceases to be used. All periods have been restated to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Terminals and synthetic fuels businesses generated net earnings from discontinued operations of $83 million and $198 million for the years ended December 31, 2007 and 2005, respectively. Net losses from discontinued operations for Terminals and synthetic fuels businesses were $37 million for the year ended December 31, 2006.

The change in net loss from discontinued operations of $37 million for the year ended December 31, 2006, to net earnings from discontinued operations of $83 million for the year ended December 31, 2007, is primarily due to increased tax credits generated due to higher production of coal-based solid synthetic fuels, unrealized mark-to-market gain on derivative contracts in 2007 and the impairment of synthetic fuels assets recorded in 2006. These favorable items are partially offset by an increase in the tax credit reserve due to the increase in production and the change in the relative oil prices, which indicated a higher estimated phase-out of tax credits, and lower margins due to the increase in coal-based solid synthetic fuels production.

The change in net earnings from discontinued operations of $198 million for the year ended December 31, 2005, to net loss from discontinued operations of $37 million for the year ended December 31, 2006, is primarily due to lower synthetic fuels production as a result of high oil prices, which increased the potential phase-out of tax credits and the impairment of synthetic fuels assets recorded in 2006.

GAS OPERATIONS

On October 2, 2006, we sold Gas to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes (See Note 3C).

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

Gas operations generated net earnings from discontinued operations of $4 million, $82 million and $48 million for the years ended December 31, 2007, 2006 and 2005, respectively. The increase in net earnings from discontinued operations during 2006 is primarily due to increased production, higher market prices and mark-to-market gains on gas hedges.

PROGRESS TELECOM, LLC

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

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

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications (See Note 3F).

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

COAL MINING BUSINESSES

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an estimated after-tax loss of $10 million for the sale of these assets (See Note 3G).

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va., and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves.

Net losses from discontinued operations for the coal mining business were $11 million, $4 million and $11 million for the years ended December 31, 2007, 2006 and 2005, respectively.

PROGRESS RAIL

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

Net earnings from discontinued operations for Progress Rail were $5 million for the year ended December 31, 2005.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Utility Regulation

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

Asset Impairments

As discussed in Note 9, we evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. Examples of these indicators include current period losses combined with a history of losses, a projection of continuing losses, a significant decrease in the market price of a long-lived asset group, or the likelihood that an asset group will be disposed of significantly prior to the end of its useful life. If an 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. Performing an impairment test on long-lived assets involves management's judgment in areas such as identifying circumstances indicating an impairment may exist, identifying and grouping affected assets at the appropriate level, and developing the undiscounted cash flows associated with the asset group. Estimates of future cash flows contemplate factors such as expected use of the assets, future production and sales levels, and expected fluctuations of prices of commodities sold and consumed. Therefore, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

The carrying value of our total utility plant, net is $16.612 billion at December 31, 2007. The carrying value of our total diversified business property, net is $6 million at December 31, 2007. In addition, we have certain diversified business property with a carrying value of $38 million at December 31, 2007, included in net assets to be divested (See Note 3I). Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred.

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

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

Goodwill

As discussed in Note 8, we account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2007 and 2006, each of which indicated no impairment. If the fair values for the utility segments were lower by 10 percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2007 and 2006, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

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

Synthetic Fuels Tax Credits

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (See Note 3B). The production and sale of the synthetic fuels from these facilities qualified for tax credits under Section 29/45K if certain requirements were satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the synthetic fuels were produced from a facility placed in service before July 1, 1998. For 2005 and prior years, the amount of Section 29 credits that we were allowed to generate in any calendar year was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized through December 31, 2005, are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. For 2006 and 2007, in accordance with federal legislation, the Section 29 tax credits have been redesignated as a Section 45K general business credit, which removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision allowed us to produce synthetic fuels at a higher level than we have historically produced, had we chosen to do so. The synthetic fuels tax credit program expired at the end of 2007.

In addition, Section 29/45K provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeded a certain threshold value (the Threshold Price), the amount of tax credits was reduced for that year. Also, if the Annual Average Price increased high enough (the Phase-out Price), the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation. We estimate that the 2007 Annual Average Price will result in an approximate 70 percent phase-out of the synthetic fuels tax credits related to synthetic fuels production in 2007. This estimate is derived from our estimates of the 2007 Threshold Price and Phase-out Price of $57 per barrel and $71 per barrel, respectively, based on an estimated inflation adjustment for 2007. For 2007 synthetic fuels production, the 2007 Annual Average Price is not known until after the end of the year. We recorded the 2007 tax credits based on our estimates of what we believe the Annual Average Price will be for 2007. Any portion of the tax credits that were phased out based on the projected 2007 Annual Average Price exceeding the Threshold Price was not recorded

See further discussion in "Other Matters – Synthetic Fuels Tax Credits."

Pension Costs

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

Due to an increase in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, we increased the discount rate to approximately 6.20% at December 31, 2007, from approximately 5.95% at December 31, 2006, which will decrease the 2008 benefit costs recognized, 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. Plan assets performed well in 2007, with returns of approximately 13%. That positive asset performance will result in decreased pension costs in 2008, all other factors remaining constant. In addition, contributions to pension plan assets in 2007 and 2008 will result in decreased pension costs in 2008 due to increased asset returns, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2008 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2008 will be $10 million to $20 million, compared with $31 million recognized in 2007.

We have pension plan assets with a fair value of approximately $2.0 billion at December 31, 2007. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2005, we elected to lower our expected rate of return from 9.25% to 9.0%. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 0.25% change in the expected rate of return for 2007 would have changed 2007 pension costs by approximately $4 million.

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

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

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

Effective February 8, 2006, the Energy Policy Act of 2005 (EPACT) provisions enacted the Public Utility Holding Company Act of 2005 (PUHCA 2005). Progress Energy is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to the issuance and sale of securities and the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend to and borrow from each other. A nonutility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and nonutility money pools but cannot borrow funds. Pursuant to PUHCA 2005, utility holding companies are allowed to continue to engage in financings authorized by the SEC, provided the authorization orders have been filed with the FERC and the holding company continues to comply with such orders, terms and conditions. We have filed all such SEC orders with the FERC; therefore, we are permitted to continue all such financing transactions.

Cash from operations, asset sales, short-term and long-term debt and limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2008. For the fiscal year 2008, we expect to realize an aggregate amount of approximately $100 million from the sale of stock through these plans.

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

Historical for 2007 as Compared to 2006 and 2006 as Compared to 2005

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2007, 2006 and 2005. Net cash provided by operating activities for the three years ended December 31, 2007, 2006 and 2005, was $1.252 billion, $2.001 billion, and $1.467 billion, respectively.

Cash from operating activities for 2007 decreased when compared with 2006. The $749 million decrease in operating cash flow was primarily due to $472 million in income tax impacts, largely driven by income tax payments related to the sale of Gas, the $347 million payment made to exit the Georgia contracts (See Note 3A); a $279 million decrease in the recovery of fuel costs, and $65 million in premiums paid for derivative contracts in our synthetic fuels businesses. These impacts were partially offset by a $157 million decrease in inventory purchases in 2007, primarily related to coal purchases at the Utilities; $106 million of working capital changes related to the divestiture of CCO; and $47 million in net refunds of cash collateral previously paid to counterparties on derivative contracts in the current year compared to $47 million in net cash payments in the prior year at PEF. The decrease in recovery of fuel costs is due to a $335 million decrease at PEF driven by the 2006 recovery of previously under-recovered fuel costs, partially offset by a $56 million increase in the recovery at PEC driven by the 2007 recovery of previously under-recovered fuel costs.

Cash from operating activities for 2006 increased when compared with 2005. The $534 million increase in operating cash flow was primarily due to a $713 million increase in the recovery of fuel costs at the Utilities, a $248 million increase from the change in accounts receivable, approximately $103 million of proceeds received from the restructuring of a long-term coal supply contract at our discontinued terminals operations, and $72 million related to recovery of storm restoration costs at PEF. These impacts were partially offset by $141 million related to a wholesale customer prepayment in 2005 at PEC, as discussed below, a $108 million decrease from the change in accounts payable and a $96 million net increase in tax payments in 2006 compared to 2005. The increase in recovery of fuel costs was largely driven by the recovery of previously under-recovered 2005 fuel costs. The $248 million change in accounts receivable included $147 million at PEC, principally driven by the timing of wholesale sales, and $47 million at PEF, primarily related to timing of receipts. The $108 million decrease from the change in accounts payable was primarily related to our discontinued and abandoned operations (See Note 3).

In November 2005, PEC entered into a contract with the Public Works Commission of the City of Fayetteville, North Carolina (PWC), in which the PWC prepaid $141 million in exchange for future capacity and energy power sales.

The prepayment covered approximately two years of electricity service and included a prepayment discount of approximately $16 million

In 2007 and 2006, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. In 2005, PEF received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7C for additional information.

INVESTING ACTIVITIES

Net cash (used) provided by investing activities for the three years ended December 31, 2007, 2006 and 2005, was $(1.457) billion, $127 million and $(1.144) billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.199 billion and $1.546 billion in 2007 and 2006, respectively, or approximately 100 percent of consolidated capital expenditures for continuing operations in both 2007 and 2006. 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 $675 million in 2007 and $1.657 billion in 2006, cash used in investing activities increased by $602 million. The increase in 2007 was primarily due to a $539 million increase in gross property additions at the Utilities, primarily at PEF, and a $114 million increase in nuclear fuel additions, partially offset by a decrease in property additions at our diversified businesses, most of which have been discontinued or abandoned. At PEC, utility property additions primarily related to an increase in spending for compliance with the Clean Smokestacks Act. At PEF, the increase in utility property additions is primarily due to environmental compliance projects, repowering the Bartow Plant to more efficient natural gas-burning technology, which will not be completed until 2009, and nuclear and transmission projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1.657 billion in 2006 and $475 million in 2005, cash used in investing activities decreased by $89 million in 2006 when compared with 2005. The decrease in 2006 was primarily due to a $319 million increase in net proceeds from available-for-sale securities and other investments, a $12 million decrease in nuclear fuel additions, and a $17 million decrease in other investing activities, largely offset by a $333 million increase in capital expenditures for utility property. At PEC, the increase in utility property was primarily due to environmental compliance and mobile meter reading project expenditures. At PEF, the increase in utility property was primarily due to repowering the Bartow Plant to more efficient natural gas-burning technology, which will not be completed until 2009; various distribution, transmission and steam production projects; and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. The increase in utility property additions was partially offset by an $84 million decrease related to diversified businesses, which have primarily been discontinued or abandoned. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

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 3A), working capital adjustments for Gas, and the sale of poles at Progress Telecommunications Corporation.

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

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

FINANCING ACTIVITIES

Net cash provided (used) by financing activities for the three years ended December 31, 2007, 2006 and 2005, was $195 million, $(2.468) billion and $227 million, respectively. See Note 12 for details of debt and credit facilities.

The increase in net cash provided by financing activities for 2007 compared to 2006 primarily related to the issuance of $750 million in long-term debt at PEF and the $1.7 billion reduction in holding company debt in 2006, as discussed below.

For 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, were used to reduce holding company debt by $1.7 billion. The increase in cash used in financing activities for 2006 compared to 2005 was primarily related to the retirement of long-term debt in 2006, as discussed below, and a decrease in the proceeds from issuances of long-term debt.

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 revolving credit agreement (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.
- On December 13, 2007, PEF filed a shelf registration statement with the SEC, which became effective with the SEC on January 8, 2008. The registration statement will allow PEF to issue up to $4 billion in first mortgage bonds, debt securities and preferred stock in addition to $250 million of previously registered but unsold securities.
- Progress Energy issued approximately 3.4 million shares of common stock resulting in approximately $151 million in proceeds from its Investor Plus Stock Purchase Plan and its stock option plan. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million to meet the requirement of the Investor Plus Stock Purchase Plan. For 2007, the dividends paid on common stock were approximately $627 million.

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. The net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds were used to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006, effectively terminating our $800 million 364-day credit agreement as discussed below.
- On March 31, 2006, Progress Energy, as a well-known seasoned issuer, filed a shelf registration statement with the SEC, which became effective upon filing with the SEC. Progress Energy's board of directors has authorized the issuance and sale by the Parent of up to $1.679 billion aggregate principal amount of various securities (See "Credit Facilities and Registration Statements").
- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006 (See "Credit Facilities and Registration Statements").
- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").

- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility (See "Credit Facilities and Registration Statements").
- On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.
- On November 1, 2006, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $60 million of its 7.17% Medium-Term Notes with available cash on hand.
- On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- Progress Energy issued approximately 4.2 million shares of common stock resulting in approximately $185 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 million.

2005

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was subsequently terminated on May 16, 2005. In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent. In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, the $800 million of 6.75% Senior Notes was retired, thus effectively terminating the 364-day credit agreement.
- PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015; $200 million of First Mortgage Bonds, 5.70% Series due 2035; and $400 million of First Mortgage Bonds, 5.25% Series due 2015. PEC paid at maturity $300 million in 7.50% Senior Notes. PEC also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on June 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.
- PEF issued $300 million in Mortgage Bonds, 4.50% Series due 2010 and $450 million in Series A Floating Rate Senior Notes due 2008. PEF paid at maturity $45 million in 6.72% Medium-Term Notes, Series B. PEF also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on March 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.
- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 4.6 million shares for proceeds of approximately $199 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2005, the dividends paid on common stock were approximately $582 million.

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, 2007, 2006 and 2005. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels businesses, whose operations have been reclassified to discontinued operations, have historically produced significant earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). These tax credits have yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. As of December 31, 2007, we have carried forward $830 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.

With the exception of the anticipated proceeds in 2008 from the sale of our coal mining and terminals operations (See Notes 3B and 3G), the absence of cash flow resulting from divested businesses is not expected to impact our future liquidity or capital resources as these businesses in the aggregate have been largely cash flow neutral over the last several years.

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

We issue commercial paper to meet short-term liquidity needs. In the latter half of 2007, the short-term credit markets tightened, resulting in higher interest rate spreads and shorter durations. Currently, the market has improved; however, there has been volatility on commercial paper spreads, as the supply of short-term commercial paper has increased following recent actions by the Federal Open Market Committee. If liquidity conditions deteriorate and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing from our RCAs, issuing short-term floating rate notes, and/or issuing long-term debt.

Progress Energy has approximately $9.7 billion in outstanding debt. Only $860 million of our debt is insured. These bonds are obligations of the Utilities and are traded in the tax-exempt auction rate securities market. Ambac Assurance Corporation insures approximately $620 million of the bonds and XL Capital Assurance, Inc. insures the remaining $240 million. To date, auctions for the Utilities' bonds have seen an increase in the interest rates that are periodically reset at each auction. Since the downgrade of XL Capital Assurance, Inc. on February 7, 2008, by Moody's Investors Service, Inc. (Moody's), we have seen additional market volatility and an increase in the reset interest rates for a portion of our tax-exempt bonds. If additional downgrades by Moody's or Standard & Poor's Rating Services (S&P) occur, we could see additional volatility in this market and the potential for higher rate resets. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

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

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

At December 31, 2007, the current portion of our long-term debt was $877 million, which we expect to fund with a combination of cash from operations, proceeds from sales of assets, commercial paper borrowings and long-term debt. See Note 3 for additional information on asset sales.

REGULATORY MATTERS AND RECOVERY OF COSTS

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

PEC Base Rates

PEC's base rates are subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act 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.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

PEC Pass-through Clause Cost Recovery

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kWh, or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006; $48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year. On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

As discussed further in "Other Matters – Regulatory Environment," South Carolina and North Carolina state energy legislation that became law in 2007 may impact our liquidity over the long term. Among other provisions, these state energy laws provide mechanisms for recovery of certain baseload generation construction costs and expand annual fuel clause mechanisms so that additional costs may be recovered annually.

Comprehensive energy legislation enacted in 2007 in North Carolina expanded the costs that may be recovered annually under the fuel clause, including costs of reagents used in emissions control technologies (commodities such as ammonia and limestone), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause. Energy legislation enacted in 2007 in South Carolina expanded the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of emissions control technologies. We anticipate PEC's reagent and purchased power costs eligible for jurisdictional recovery under the North Carolina and South Carolina energy laws will total approximately $50 million in 2008.

The North Carolina law mandates minimum Renewable Energy and Energy Efficiency Portfolio Standards (REPS) beginning in 2012. Utilities are allowed to recover the premium to be paid to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligation under the REPS, regardless of the actual renewables generated or purchased. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

In addition, the North Carolina law also allows PEC to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. DSM programs include any program or initiative that shifts the timing of electricity use from peak to nonpeak periods. PEC has begun implementing a series of DSM and energy-efficiency programs and for the year ended December 31, 2007, deferred $2 million of implementation and program costs for future recovery.

See "Other Matters – Regulatory Environment" for additional information about state and federal legislation.

PEF Base Rates

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

On October 23, 2007, the FPSC approved a stipulation and settlement agreement that settled all issues related to recovery of the revenue requirements of Hines Unit 2 and Hines Unit 4 and provided that PEF shall 1) increase its base rates for the revenue requirements of Hines Unit 2 and Hines Unit 4 and 2) simplify the implementation of the base rate increase of $89 million by making it effective with the first billing cycle in January 2008. The revenue requirements of Hines Unit 2 were previously being recovered through the fuel clause.

PEF Pass-through Clause Cost Recovery

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008, and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased effective January 1, 2008, by $2.73 for the first 1,000 kWh. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF was over-recovered in fuel and capacity costs by $140 million, over-recovered in conservation costs by $14 million, over-recovered in environmental compliance by $5 million and had accrued disallowed fuel costs of $14 million as discussed below.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority 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. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices were prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate Crystal River Unit No. 3 Nuclear Plant (CR3), bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. On February 8, 2007, the FPSC issued an order approving PEF's request for a need determination to uprate through a multi-stage uprate to be completed by 2012. PEF's need determination filing included estimated project costs of approximately $382 million. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing on the matter to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, instrumentation modifications for improved accuracy, estimated at $6 million through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the ECRC, which were estimated to be $31 million at December 31, 2007. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR through the ECRC (see "Other Matters – Environmental Matters" for discussion regarding CAMR). The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $1.3 billion to $2.3 billion.

Storm Cost Recovery

On August 29, 2006, the FPSC approved a settlement agreement related to PEF's storm cost-recovery docket that allowed PEF to extend its then-current two-year storm surcharge. The requested 12-month extension, which began in August 2007, will replenish the existing storm reserve by an estimated $126 million. In the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. Intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

Nuclear Cost Recovery

The FPSC approved new rules on February 13, 2007, that allow PEF to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once 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. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. 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.

Other Regulatory Matters

Additionally, on July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry, and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. We cannot currently predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry, and emissions reduction targets that are similar to those contained in the governor's executive orders. We cannot currently predict the impacts to our liquidity of complying with these executive orders and the Florida Energy Commission's recommendations.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. On June 18, 2007, compliance with 83 FERC-approved reliability standards became mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. On December 20, 2007, the FERC approved three additional planning and operating reliability standards. Additionally, on January 17, 2008, the FERC approved eight mandatory critical infrastructure protection reliability standards to protect the bulk power system against potential disruptions from cyber security breaches.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our cash flows.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2007.

As shown in the table below, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. We anticipate our regulated capital expenditures will increase in 2008 and 2009, primarily due to increased spending on environmental initiatives and current growth and maintenance projects. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2007**	2008	2009	2010
Regulated capital expenditures	**$1,874**	$2,420	$2,080	$1,670
Nuclear fuel expenditures	**228**	260	290	270
AFUDC – borrowed funds	**(16)**	(40)	(50)	(40)
Other capital expenditures	**10**	20	20	20
Total before potential nuclear construction	**2,096**	2,660	2,340	1,920
Potential nuclear construction[a]	**94**	160	520	850
Total	**$2,190**	$2,820	$2,860	$2,770

[a] Expenditures for potential nuclear construction are net of AFUDC – borrowed funds and include land, development, licensing, equipment and associated transmission. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build; final contract negotiations; timing and escalation of project costs; and the percentages, if any, of joint ownership. These expenditures, which are primarily at PEF, are subject to cost-recovery provisions in the Utilities' respective jurisdictions (see discussion under "Other Matters – Nuclear").

Regulated capital expenditures for 2008, 2009 and 2010 in the table above include approximately $730 million, $350 million and $130 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2008, 2009 and 2010 include $180 million, $70 million and $80 million, respectively, at PEC and $550 million, $280 million and $50 million, respectively, at PEF. We currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $700 million at PEC and in excess of $1.9 billion at PEF through 2018, which is the latest compliance target date for current air and water quality regulations. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

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

CREDIT FACILITIES AND REGISTRATION STATEMENTS

The following table summarizes our RCAs and available capacity at December 31, 2007:

(in millions)	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.				
Five-year (expiring 5/3/11)	$1,130	$–	$220	$910
PEC				
Five-year (expiring 6/28/10)	450	–	–	450
PEF				
Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities	$2,030	$–	$220	$1,810

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

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

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 Progress Energy's RCA are based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's and BBB by S&P. Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P. Fees and interest rates under PEF's RCA are based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB by S&P.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2007. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2007, the calculated ratios, pursuant to the terms of the agreements, are as disclosed in Note 12.

Progress Energy, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which Progress Energy may issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2007, Progress Energy has the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

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

PEF has on file with the SEC a shelf registration statement under which it can issue up to $4.250 billion of various long-term debt securities and preferred stock.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2007, PEC and PEF could issue up to $3.657 billion and $2.408 billion, respectively, based on property additions and $1.827 billion and $175 million, respectively, based upon retirements of previously issued first mortgage bonds.

CAPITALIZATION RATIOS

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

	2007	2006
Common stock equity	**45.7%**	47.2%
Preferred stock and minority interest	**1.0%**	0.6%
Total debt	**53.3%**	52.2%

CREDIT RATING MATTERS

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

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

[a] Guaranteed by Progress Energy, Inc. and Florida Progress
[b] Guaranteed by Florida Progress

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

On September 6, 2007, S&P upgraded the first mortgage bonds of both PEC and PEF to A- from BBB+ as a result of a methodology change for collateral coverage requirements. Because both PEC and PEF had asset to potential secured debt ratios of less than 1.5, they were assigned a recovery rating of 1, which qualified for a one-notch increase over their corporate credit ratings.

On July 13, 2007, Fitch Ratings upgraded the long-term ratings of both PEC and PEF to A- from BBB+ and revised their rating outlooks to stable from positive. Fitch Ratings cited cash flow coverage and leverage credit ratios more consistent with the A rating category at the Utilities, sound utility operations and operations in historically favorable regulatory environments as the primary factors for the upgrades. Fitch Ratings also noted lowered group linkage risks for PEC and PEF resulting from improved business risk at the Parent due to the sale or wind-down of non-utility operations and reduced debt.

On June 15, 2007, Moody's upgraded the corporate credit rating for PEC to A3 from Baa1 and revised its outlook to stable from positive. Moody's cited strong cash flow coverage measures and financial metrics, operations in constructive regulatory environments with growing service territories and lower debt and business risk at the Parent as the primary factors in the upgrade.

On March 15, 2007, S&P upgraded corporate credit ratings to BBB+ from BBB at Progress Energy, Inc., PEC and PEF and revised each company's outlook to stable from positive. S&P cited the significant reduction in our holding company debt and the moderation of business risk achieved by our renewed focus on our regulated utilities as the primary factors in the upgrade.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2007, we have issued $481 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). 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, 2007, 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. Amounts in the following table are estimated based upon contractual terms, and actual amounts will likely differ from amounts presented below. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2007, in the respective periods in which they are due.

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 12)	$9,668	$877	$806	$1,950	$6,035
Interest payments on long-term debt[b]	6,865	558	1,003	816	4,488
Capital lease obligations (See Note 22B)	657	28	57	63	509
Operating leases (See Note 22B)	740	62	66	58	554
Fuel and purchased power[c] (See Note 22A)	17,644	2,473	3,778	2,534	8,859
Other purchase obligations[c] (See Note 22A)	1,228	808	324	32	64
Minimum pension funding requirements[e]	193	34	105	54	–
Uncertain tax positions[f] (See Note 14)	–	–	–	–	–
Other commitments[g]	133	13	27	27	66
Total	$37,128	$4,853	$6,166	$5,534	$20,575

(a) Our maturing debt obligations are generally expected to be repaid with asset sales and cash from operations or refinanced with new debt issuances in the capital markets
(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2007
(c) Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
(d) We have additional contractual obligations associated with our discontinued CCO operations, which are not reflected in this table These obligations include other purchase obligations of $3 million each for 2008 and 2009
(e) Projected pension funding status is based on current actuarial estimates and is subject to future revision
(f) Uncertain tax positions of $93 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008
(g) In 2008, PEC must begin transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year

OTHER MATTERS

Synthetic Fuels Tax Credits

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants The tax credits associated with synthetic fuels in a particular year were phased out if annual average market prices for crude oil exceeded certain prices. Synthetic fuels were generally not economical to produce and sell absent the credits The synthetic fuels tax credit program expired at the end of 2007

TAX CREDITS

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

Total Section 29/45K credits generated through December 31, 2007 (including those generated by Florida Progress prior to our acquisition), were approximately $2.028 billion, of which $1.054 billion has been used to offset regular federal income tax liability, $830 million is being carried forward as deferred tax credits and $144 million has been reserved due to the estimated phase-out of tax credits due to high oil prices, as described below

IMPACT OF CRUDE OIL PRICES

Section 29 provided that if the Annual Average Price exceeded the Threshold Price, the amount of Section 29/45K tax credits was reduced for that year. Also, if the Annual Average Price exceeded the Phase-out Price, the Section 29/45K tax credits were eliminated for that year The Threshold Price and the Phase-out Price were adjusted annually for inflation

If the Annual Average Price fell between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits were reduced depended on where the Annual Average Price fell in that continuum. The Department of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2006 was published on April 4, 2007. Based on the Annual Average Price for calendar year 2006 of $59.68, our synthetic fuels tax credits generated during 2006 were reduced by 33 percent, or approximately $35 million. The Annual Average Price for calendar year 2007 is expected to be published in early April 2008.

On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities. As discussed below, the decision to idle production was based on the high level of oil prices, and the resumption of synthetic fuels production was dependent upon a number of factors, including a reduction in oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. The operation of synthetic fuels facilities on behalf of third parties continued through late 2007. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased in late December 2007, we reclassified the operations of our synthetic fuels businesses as discontinued operations in the fourth quarter of 2007.

We estimate that the 2007 Threshold Price will be approximately $57 per barrel and the Phase-out Price will be approximately $71 per barrel, based on an estimated inflation adjustment for 2007. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding daily New York Mercantile Exchange (NYMEX) prompt month settlement price for light sweet crude oil. Through December 31, 2007, the average NYMEX settlement price for light sweet crude oil was $72.35 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price and assuming that the $5 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2007, we estimate that the synthetic fuels tax credit amount for 2007 will be reduced by approximately 70 percent. Therefore, we reserved 70 percent or approximately $144 million of the $205 million of tax credits generated during 2007. The final calculations of any reductions in the value of the tax credits will not be determined until April 2008 when final 2007 oil prices are published.

In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a NYMEX basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production and was marked-to-market with changes in fair value recorded through earnings. The derivative contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact on 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed below in "Sales of Partnership Interests" and in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo in March 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts, including $57 million attributable to Ceredo, of which $42 million was attributed to minority interest for the portion of the gain subsequent to disposal. See Note 17A and "Quantitative and Qualitative Disclosures About Market Risk" and for a discussion of market risk and derivatives.

IMPAIRMENT OF SYNTHETIC FUELS AND OTHER RELATED LONG-LIVED ASSETS

We monitor our long-lived assets for impairment as warranted. With the idling of our synthetic fuels facilities during the second quarter of 2006 due to the high level of oil prices, we performed an impairment evaluation of our synthetic fuels and other related operating long-lived assets. The impairment test considered numerous factors, including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities. Based on the results of the impairment test, we recorded pre-tax impairment charges of $91 million ($55 million after-tax) during the quarter ended June 30, 2006 (See Notes 8 and 9). These charges represent the entirety of the asset carrying value of our synthetic fuels intangible assets and manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. As discussed in Note 3B, these charges have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

SALES OF PARTNERSHIP INTERESTS

In March 2007, we disposed of, through our subsidiary Progress Fuels, our 100 percent ownership interest in Ceredo, a subsidiary that produces and sells 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 are due as we produce and sell qualifying coal-based solid synthetic fuels on behalf of the buyer. During 2007, we produced 2.7 million tons. In accordance with the terms of the agreement, we received payments on the note related to 2007 production of $49 million in 2007 and $5 million subsequent to year-end. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. Subsequent to the disposal, we remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R), but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there was no net earnings impact from Ceredo's operations. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer, which increases the loss on disposal or reduces any potential deferred gain. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods (See Note 3J and Note 22C).

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of our synthetic fuels facilities. The transactions were structured such that proceeds from the sales would be received over time, which was typical of such sales in the industry. Gains from the sales are recognized on a cost-recovery basis. Gain recognition is dependent on the synthetic fuels production qualifying for Section 29/45K tax credits and the value of such tax credits, as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona were deferred. Due to the impact on production from the 2007 idling of the synthetic fuels facilities as discussed above and pursuant to the terms of the sales agreements, in January 2008, the purchasers abandoned their interests in Colona. We recognized a $4 million gain and $30 million gain on these transactions in the years ended December 31, 2006 and 2005, respectively, which have been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3L). In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gain.

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

Regulatory Environment

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

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

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

On December 19, 2007, the president signed into law the federal Energy Independence and Security Act of 2007. The legislation strengthened Corporate Average Fuel Economy standards for automotive manufacturers' fleets of passenger cars and light trucks and significantly increased the amount of ethanol required to be used as a gasoline additive. The legislation also provided incentives for the development of plug-in hybrid electric vehicles and created new energy-efficiency standards in commercial, residential and governmental use. In addition, the legislation authorized increased funding for research into the use of carbon capture and storage technology, and directs states to consider "smart grid" improvements to transmission infrastructure. The law did not contain any provisions for a federal Renewable Portfolio Standard.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law mandates minimum REPS for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state's electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. The premium to be paid by electric utilities to comply with the requirements, above the cost they would have otherwise incurred to meet consumer demand, is to be recovered through an annual clause. The annual amount that can be recovered through the REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations under the REPS, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the REPS requirements if the NCUC determines it is in the public interest to do so. The recovery cap requirement begins in 2008 and, as a result, PEC will begin deferring certain costs associated with renewable energy purchases in 2008. These costs are expected to be immaterial in 2008.

The law allows the utility to meet a portion of the REPS with energy reductions achieved through energy-efficiency programs. Energy-efficiency programs include any program or activity implemented after January 1, 2007, that results in less energy being used to perform the same function. Through the year 2020, a utility can use energy-efficiency programs to satisfy up to 25 percent of their REPS; beginning in 2021, these programs may constitute up to 40 percent of the requirements.

The law allows the utility to recover the costs of new DSM and energy-efficiency programs through an annual DSM clause. The law allows the utility to capitalize those costs that are 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 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 and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs for future recovery for the year ended December 31, 2007.

The law also expands the definition of the traditional fuel clause so that additional costs may be recovered annually. These additional costs include costs of reagents (commodities such as ammonia and limestone used in emissions control technologies), the avoided costs associated with renewable energy purchases and certain components of purchased power not previously recoverable through the fuel clause (see additional discussion below). The North Carolina law also authorizes the NCUC to allow annual prudence reviews of the construction costs of a baseload generating plant if requested by the public utility that is constructing the plant and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction.

On October 26, 2007, the NCUC issued its proposed rules for implementation of the law. PEC expects final rules to be issued by the end of the first quarter of 2008. Until the rulemaking process is completed, we cannot predict the costs of complying with the law. PEC would be able to annually recover its reasonable prudent compliance costs.

During 2007, the South Carolina legislature ratified new energy legislation, which became law on May 3, 2007. Key elements of the law include expansion of the annual fuel clause mechanism to include recovery of the costs of reagents used in the operation of PEC's emissions control technologies (see additional discussion below). The law also includes provisions to provide base rate cost recovery for upfront development costs associated with nuclear baseload generation and construction costs associated with nuclear or coal baseload generation without a base rate proceeding and the ability to recover financing costs for new nuclear baseload generation through annual clauses.

On November 30, 2007, PEC filed a petition with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency program expenses pending the filing of application requesting a DSM and energy-efficiency program expense clause to recover such program costs. On December 12, 2007, the SCPSC granted PEC's petition. As a result, through December 31, 2007, PEC deferred an immaterial amount of implementation and program costs for future recovery in the South Carolina jurisdiction.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions.

Among other things, the executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers, who generate electricity from on-site renewable technologies of up to 1 MW in capacity, to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). The FPSC has held meetings regarding the renewable portfolio standard but no actions have been taken or rules issued. The Energy and Climate Action Team appointed by the governor submitted its initial recommendations for implementation of the governor's executive orders on November 1, 2007. The recommendations encourage the development and implementation of energy-efficiency and conservation measures, implementation of a climate registry and consideration of a cap-and-trade approach to reducing the state's greenhouse gas emissions. Additional development and discussion of the recommendations will occur through a stakeholder process in 2008. The Florida Department of Environmental Protection held its first rulemaking workshop on the greenhouse gas emissions cap on August 22, 2007, and a second workshop on December 5, 2007. We anticipate drafts of the rule will be issued in 2008. In addition, the Florida Energy Commission, which was established by the Legislature in 2006, published its energy policy and climate change recommendations on December 31, 2007. The report includes proposed legislative language that would implement energy-efficiency and conservation programs, participation in the multi-state Climate Registry and emissions reduction targets that are similar to those contained in the governor's executive orders.

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

On April 10, 2007, the FPSC adopted a rule that specifies what storm costs will be recoverable and whether such recoverable costs would be offset against a utility's storm reserve fund or recoverable through its base rates. PEF does not believe that compliance with this rule will materially increase its costs.

EPACT, among other provisions, gave the FERC accountability for system reliability and the authority to impose civil penalties. EPACT provides procedures and rules for the establishment of an electric reliability organization (ERO) that will propose and enforce mandatory reliability standards. On July 20, 2006, the FERC certified the North American Electric Reliability Corporation (NERC) as the ERO. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards in particular regions of the country by entering into delegation agreements with regional entities. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

As discussed in "Future Liquidity and Capital Resources – Other Regulatory Matters," during 2007 and 2008, the FERC approved a significant number of reliability standards developed by the NERC and set aside other standards pending further development. Compliance with FERC-approved reliability standards is mandatory for all registered users, owners and operators of the bulk power system, including PEC and PEF. Prior to the FERC action, electric utility industry compliance with the NERC standards had been voluntary.

Based on FERC's directive to revise 56 of the adopted standards, we expect standards to migrate to more definitive and enforceable requirements over time. We are committed to meeting those standards. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Prior to the effective date of mandatory compliance with the reliability standards, PEC self-reported two noncompliances and PEF self-reported three noncompliances. Entities responsible for enforcement of mandatory reliability standards have proposed that entities that self-reported noncompliance prior to the effective date and pursue aggressive mitigation plans will not be assessed fines. Subsequent to the effective date, PEC self-reported three noncompliances with voluntary standards and PEF self-reported one noncompliance with voluntary standards and one noncompliance with a mandatory standard. PEC and PEF have submitted mitigation plans to address the self-reported noncompliance. The costs of executing the mitigation plans are not expected to have a significant effect on our results of operations or liquidity.

Legal

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

Increasing Energy Demand

Meeting the anticipated 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 energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. Our energy-efficiency program provides simple, low-cost ways for residential customers to reduce energy use, promotes home energy checks, provides tools and programs for large and small businesses to minimize their energy use and provides an interactive internet Web site with online calculators, programs and efficiency tips.

We are actively engaged in a variety of alternative energy projects, including solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from hog waste and other plant or animal sources.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated 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. While we pursue expansion of energy-efficiency and conservation programs, PEC has announced a two-year moratorium on constructing new coal-fired plants and that if PEC goes ahead with a new nuclear plant, the new plant would not be online until at least 2018 (see "Nuclear" below).

As authorized under EPACT, on October 4, 2007, the United States Department of Energy (DOE) published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects. Congress has approved $4 billion in loan guarantees, with the DOE seeking an additional $9 billion in loan guarantees in its fiscal 2008 budget request. Initial applications for loan guarantees were for non-nuclear projects but it is expected that approval of additional funding could result in guarantees being available for nuclear generation projects. 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.

On November 14, 2006, PEC filed an application with the NRC for a 20-year extension of the Harris operating license. The license renewal application for Harris is currently under review by the NRC with a decision expected in 2008.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 5 and 22D).

We previously announced that we are pursuing development of COL applications to potentially construct new nuclear plants in North Carolina and Florida. Filing of a COL is not a commitment to build a nuclear plant but is a necessary step to keep open the option of building a plant or plants. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We have 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. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, the new plant would not be online until at least 2018 (See "Increasing Energy Demand" above).

On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion. We have selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. PEF expects to file the application for the COL in 2008. If we receive approval from the NRC and applicable state agencies, and if the decision to build is made, safety-related construction activities could begin as early as 2012, and a new plant could be online in 2016 (See "Increasing Energy Demand" above). In 2007, PEF completed the purchase of approximately 5,000 acres for the Levy County site and associated transmission needs. PEF anticipates filing a Determination of Need petition with the FPSC in 2008.

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. The Florida Department of Community Affairs (FDCA) reviewed the proposed changes to the comprehensive land use plan and in their report, the FDCA expressed concerns related to the intensity of use and environmental suitability for some of the proposed amendments impacting PEF's proposed Levy County nuclear site. We anticipate that the Levy County Planning Commission will resolve the FDCA's concerns without impact to the potential project schedule. We cannot predict the outcome of this matter.

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

In accordance with provisions of Florida's comprehensive energy bill enacted in 2006, the FPSC ordered new rules in December 2006 that would allow investor-owned utilities such as PEF to request recovery of certain planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned once 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. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

In 2007, the South Carolina legislature ratified new energy legislation, which includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. The North Carolina legislature ratified new energy legislation, which authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

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 be precisely estimated.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, 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 these potential claims cannot be predicted. No material claims are currently pending. Hazardous and solid waste management matters are discussed in detail in Note 21A.

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

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which would likely result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxides (NO_x), 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 that will be installed pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAVR and mercury regulation, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

The following table contains information about our current estimates of capital expenditures to comply with environmental laws and regulations described below. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. PEC has completed installation of controls to meet the NO_x SIP Call Rule under Section 110 of the Clean Air Act (NO_x SIP Call) requirements. The NO_x SIP Call is not applicable to Florida. Expenditures for the NO_x SIP Call include the cost to install NO_x controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. The air quality controls installed to comply with the NO_x SIP Call and Clean Smokestacks Act will result in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC. Our estimates of capital expenditures to comply

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2007
Clean Smokestacks Act	2002–2013	$1,100 – 1,400	$892
CAIR/CAVR/mercury regulation	2005–2018	1,500 – 2,600	333
Total air quality		2,600 – 4,000	1,225
Clean Water Act Section 316(b) [a]		–	–
Total air and water quality		$2,600 – 4,000	$1,225

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

with environmental laws and regulations are subject to periodic review and revision and may vary significantly. The timing and extent of the costs for future projects will depend upon final compliance strategies.

To date, under the first phase of Clean Smokestacks Act emission reductions, all environmental compliance projects at our Asheville Plant and several projects at our Roxboro Plant have been placed in service. The remaining projects at our two largest plants, Roxboro and Mayo, are under construction and are expected to be completed in 2008 and 2009, respectively. The remaining projects to comply with the second phase of emission reductions, which are smaller in scope, have not yet begun. These estimates are currently under review and are conceptual in nature and subject to change.

To date, expenditures at PEF for CAIR/CAVR/mercury regulation primarily relate to environmental compliance projects under construction at CR5 and CR4, which are expected to be placed in service in 2009 and 2010, respectively. See discussion of projects for Crystal River Units No. 1 and No. 2 to meet CAVR beyond-BART requirements below.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (NSR) requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The 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 were in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms. On April 2, 2007, the U.S. Supreme Court issued a ruling on an appeal of a decision of the U.S. Court of Appeals for the Fourth Circuit, in a case involving an unaffiliated utility. The Fourth Circuit held that NSR applies to projects that result in an increase in maximum hourly emissions. The U.S. Supreme Court rejected the lower court decision and held that the EPA is not required to adopt the maximum hourly emissions test but may use an actual annual emissions test to determine whether NSR applies.

On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) set aside the EPA's 2003 NSR equipment replacement rule. The rule would have provided a more uniform definition of routine equipment replacement, which is excluded from NSR applicability. The D.C. Court of Appeals denied a request by the EPA for a re-hearing regarding this matter on June 30, 2006. On November 27, 2006, the EPA filed a petition for a writ of certiorari requesting that the U.S. Supreme Court review the decision of the D.C. Court of Appeals. On April 30, 2007, the U.S. Supreme Court denied the EPA's petition. In a previous case decided in late 2005, the D.C. Court of Appeals had also set aside a provision in the NSR rule that had exempted the installation of pollution control projects from review. These projects are now subject to NSR requirements, adding time and cost to the installation process.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In March 2007, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately

$1.1 billion to $1.4 billion at the time of the filing. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are continuing to evaluate various design, technology and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the equipment. Recent legislation in North Carolina and South Carolina expanded the traditional fuel clause to include the annual recovery of reagents and certain other costs; all other O&M expenses are currently recoverable through base rates. On March 23, 2007, PEC filed a petition with the NCUC regarding future recovery of costs to comply with the Clean Smokestacks Act, and on October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, CUCA and CIGFUR supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis. See further discussion about the Clean Smokestacks Act in Note 7B. We cannot predict the outcome of this matter.

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

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

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

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR. The EPA approved the North Carolina CAIR on October 5, 2007, the South Carolina CAIR on October 9, 2007, and the Florida CAIR on October 12, 2007.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the D.C. Court of Appeals issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. On March 16, 2006, the EPA denied all pending reconsiderations, allowing the challenge to proceed. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. Oral argument has been set by the D.C. Court of Appeals for March 25, 2008. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAIR, which is very similar to the EPA's model rule. An unaffiliated utility challenged the state-adopted rule. On November 7, 2007, the Florida District Court of Appeals ruled against the challenge and in favor of the Florida Department of Environmental Protection. The outcome of these matters cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that sets mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA, the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR. The delisting rule was challenged by a number of parties. Sixteen states subsequently petitioned for a review of the EPA's determination confirming the delisting. On February 8, 2008, the D.C. Court of Appeals decided in favor of the petitioners and vacated the delisting determination and the CAMR. The exact impacts of this decision are uncertain until the court's mandate is issued. The three states in which the Utilities operate have adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the vacation of the federal CAMR will affect the state rules.

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. The reductions associated with BART begin in 2013. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. Plans for compliance with CAIR and mercury regulation may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. On December 4, 2007, the Florida Department of Environmental Protection finalized a Regional Haze implementation rule that requires sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, Bartow Unit No. 3 and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted. On December 12, 2006, the D.C. Court of Appeals decided in favor of the EPA in a case brought by the National Parks Conservation Association that alleges the EPA acted improperly by substituting the requirements of CAIR for BART for NOx and SO_2 from electric generating units in areas covered by CAIR.

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

The integrated compliance strategy PEF anticipates implementing should provide most, but not all, of the NOx reductions required by CAIR. Therefore, PEF anticipates utilizing the cap-and-trade feature of CAIR by purchasing annual and seasonal NOx allowances. Because the emission controls cannot be installed in time to meet CAIR's NOx requirements in 2009, PEF anticipates purchasing a higher level of annual and seasonal allowances in that year. The costs of these allowances would depend on market prices at the time these allowances are purchased. PEF expects to recover the costs of these allowances through its ECRC.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR, CAMR and CAVR through the ECRC (see discussion above regarding CAMR). On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy. On June 1, 2007, PEF filed a supplemental petition for approval of its compliance plan and associated contracts and recovery of costs for air pollution control projects, which included approximately $1.0 billion to $2.3 billion of estimated capital costs for the range of alternative plans. The estimated capital cost for the recommended plan, which was $1.26 billion in the June 1, 2007 filing, represents the low end of the range in the table of estimated required environmental expenditures shown above. The difference in costs between the recommended plan and the high end of the range represents the additional costs that may be incurred if pollution controls are required on Crystal River Units No. 1 and No. 2 in order to comply with the requirements of CAVR beyond BART, should reasonable progress in improving visibility not be achieved, as discussed above. The increase from the estimates filed in March 2006 is primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. The outcome of this matter cannot be predicted.

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

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

National Ambient Air Quality Standards

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

On June 20, 2007, the EPA announced proposed changes to the NAAQS for ground-level ozone. The EPA proposed to lower the 8-hour primary standard from 0.08 parts per million to a range of 0.070 to 0.075 parts per million. The two alternatives proposed for the secondary standard are to either establish a new cumulative, seasonal standard or set the secondary standard as identical to the proposed primary standard. Depending on air quality improvements expected over the next several years as current federal requirements are implemented, additional nonattainment areas may be designated in PEC's and PEF's service territories. The final rule is expected in March 2008. The outcome of this matter cannot be predicted.

Water Quality

1. General

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on the Utilities in the immediate and extended future.

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

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

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA. On July 9, 2007, the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitting authorities establish best available technology controls for minimizing adverse environmental impact at existing cooling water intake structures on a case-by-case, best professional judgment basis. On November 2, 2007, the Utility Water Act Group and several unaffiliated utilities filed petitions for writ of certiorari to the U.S. Supreme Court. On December 3, 2007, 13 states filed an amicus brief in support of the Utility Water Act Group's petition. As a result of these recent developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

3. North Carolina Groundwater Standard

In 2006, the North Carolina Environmental Management Commission granted approval for North Carolina Division of Water Quality (NCDWQ) staff to publish a notice in the North Carolina Register and schedule public hearings regarding the NCDWQ's recommendation to revise the state's groundwater quality standard for arsenic to 0.00002 milligrams/liter from 0.05 milligrams/liter. To date, no further action has been taken by the NCDWQ staff on this matter.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration favors voluntary programs. There are proposals and ongoing studies at the state and federal levels, including the state of Florida, to address global climate change that would regulate CO_2 and other greenhouse gases. See further discussion of the executive orders issued by the governor of Florida to address reduction of greenhouse gas emissions under "Other Matters – Regulatory Environment."

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking action on this important issue as discussed under "Other Matters – Increasing Energy Demand." In 2007, we issued a corporate responsibility summary report, which discusses our actions, and in 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

In a decision issued July 15, 2005, the D.C. Court of Appeals denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation. The U.S. Supreme Court agreed to hear the case and on April 2, 2007, it ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. The impact of this decision cannot be predicted.

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 mitigate such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties (See Note 17).

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

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

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

Interest Rate Risk

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

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

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

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

The following tables provide information at December 31, 2007 and 2006, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and Florida Progress-obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2008 to 2012 and thereafter and the related fair value. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

During 2007, PEF had entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, which were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017.

On July 30, 2007, PEC entered into a $50 million notional forward starting swap and on October 24, 2007, PEC

(dollars in millions) December 31, 2007	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value December 31, 2007
Fixed-rate long-term debt	$427	$400	$306	$1,000	$950	$4,865	$7,948	$8,192
Average interest rate	6.67%	5.95%	4.53%	6.96%	6.67%	6.03%	6.20%	
Variable-rate long-term debt	$450	–	$100	–	–	$861	$1,411	$1,411
Average interest rate	5.27%	–	5.69%	–	–	4.45%	4.80%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$294
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Interest rate forward contracts[b]	$200	–	–	–	–	–	$200	$(12)
Average pay rate	5.41%	–	–	–	–	–	5.41%	
Average receive rate	(c)	–	–	–	–	–	(c)	

[a] FPC Capital I – Quarterly Income Preferred Securities
[b] $100 million is for anticipated 10-year debt issue hedge maturing on April 1, 2018, and requires mandatory cash settlement on April 1, 2008. The remaining $100 million is for anticipated 30-year debt issue hedge maturing on April 1, 2038, and requires mandatory cash settlement on April 1, 2008.
[c] Rate is 3-month London Inter Bank Offering Rate (LIBOR), which was 4.70% at December 31, 2007.

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

[a] FPC Capital I – Quarterly Income Preferred Securities
[b] Rate is 3-month LIBOR, which was 5.36% at December 31, 2006
[c] Anticipated 10-year debt issue hedges matured on October 1, 2017, and required mandatory cash settlement on October 1, 2007

entered into $100 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. On September 25, 2007, PEC amended its 10-year forward starting swap in order to move the maturity date from October 1, 2017, to April 1, 2018.

On January 8, 2008, PEF entered into a combined $200 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

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, 2007 and 2006, the fair value of these funds was $1.384 billion and $1.287 billion, respectively, including $804 million and $735 million, respectively, for PEC and $580 million and $552 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of Florida Progress, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. The CVOs are derivatives and are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively. A hypothetical 10 percent decrease in the December 31, 2007, market price would result in a $3 million decrease in the fair value of the CVOs.

Commodity Price Risk

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

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

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, 2007, the only derivative commodity instruments not eligible for recovery from ratepayers related to derivative contracts entered into on January 8, 2007, to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices as discussed below. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. At December 31, 2006, derivative commodity instruments not eligible for recovery from ratepayers were included in discontinued operations as discussed below.

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

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of 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. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

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. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At December 31, 2007 and 2006, 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 2007, 2006 and 2005.

At December 31, 2007 and 2006, 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, 2007. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2007, 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, 2007, as stated in their report.

William D. Johnson
Chairman, President and Chief Executive Officer

Peter M. Scott III
Executive Vice President and Chief Financial Officer

February 28, 2008

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, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2007, 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, 2007, of the Company and our report dated February 28, 2008, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the adoption of new accounting principles in 2007 and 2006.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc , and its subsidiaries (the Company) at December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2007. 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 the Company at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 and Note 16 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting at December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte + Touche LLP

Raleigh, North Carolina
February 28, 2008

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data)			
Years ended December 31	2007	2006	2005
Operating revenues	$9,153	$8,724	$7,948
Operating expenses			
Fuel used in electric generation	3,145	3,008	2,359
Purchased power	1,184	1,100	1,048
Operation and maintenance	1,842	1,583	1,770
Depreciation and amortization	905	1,011	926
Taxes other than on income	501	500	460
Other	30	35	(3)
Total operating expenses	7,607	7,237	6,560
Operating income	1,546	1,487	1,388
Other income (expense)			
Interest income	34	59	13
Other, net	44	(16)	(1)
Total other income	78	43	12
Interest charges			
Net interest charges	605	631	588
Allowance for borrowed funds used during construction	(17)	(7)	(13)
Total interest charges, net	588	624	575
Income from continuing operations before income tax and minority interest	1,036	906	825
Income tax expense	334	339	298
Income from continuing operations before minority interest	702	567	527
Minority interest in subsidiaries' income, net of tax	(9)	(16)	(4)
Income from continuing operations	693	551	523
Discontinued operations, net of tax	(189)	20	173
Cumulative effect of change in accounting principle, net of tax	–	–	1
Net income	$504	$571	$697
Average common shares outstanding – basic	256	250	247
Basic earnings per common share			
Income from continuing operations	$2.71	$2.20	$2.12
Discontinued operations, net of tax	(0.74)	0.08	0.70
Net income	$1.97	$2.28	$2.82
Diluted earnings per common share			
Income from continuing operations	$2.70	$2.20	$2.12
Discontinued operations, net of tax	(0.74)	0.08	0.70
Net income	$1.96	$2.28	$2.82
Dividends declared per common share	$2.45	$2.43	$2.38

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2007	2006
ASSETS		
Utility plant		
Utility plant in service	$25,327	$23,743
Accumulated depreciation	(10,895)	(10,064)
Utility plant in service, net	14,432	13,679
Held for future use	37	10
Construction work in progress	1,765	1,289
Nuclear fuel, net of amortization	371	267
Total utility plant, net	16,605	15,245
Current assets		
Cash and cash equivalents	255	265
Short-term investments	1	71
Receivables, net	1,137	930
Inventory	994	936
Deferred fuel cost	154	196
Deferred income taxes	27	142
Assets to be divested	52	966
Prepayments and other current assets	155	108
Total current assets	2,775	3,614
Deferred debits and other assets		
Regulatory assets	931	1,231
Nuclear decommissioning trust funds	1,384	1,287
Miscellaneous other property and investments	448	465
Goodwill	3,655	3,655
Derivative assets	109	2
Other assets and deferred debits	379	208
Total deferred debits and other assets	6,906	6,848
Total assets	$26,286	$25,707
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 260 million and 256 million shares issued and outstanding, respectively	$6,028	$5,791
Unearned ESOP shares (2 million shares)	(37)	(50)
Accumulated other comprehensive loss	(34)	(49)
Retained earnings	2,465	2,594
Total common stock equity	8,422	8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93
Minority interest	84	10
Long-term debt, affiliate	271	271
Long-term debt, net	8,466	8,564
Total capitalization	17,336	17,224
Current liabilities		
Current portion of long-term debt	877	324
Short-term debt	201	–
Accounts payable	789	712
Interest accrued	173	171
Dividends declared	160	156
Customer deposits	255	227
Regulatory liabilities	173	76
Liabilities to be divested	8	248
Income taxes accrued	8	284
Other current liabilities	604	622
Total current liabilities	3,248	2,820
Deferred credits and other liabilities		
Noncurrent income tax liabilities	361	312
Accumulated deferred investment tax credits	139	151
Regulatory liabilities	2,539	2,543
Asset retirement obligations	1,378	1,304
Accrued pension and other benefits	763	957
Capital lease obligations	239	70
Other liabilities and deferred credits	283	326
Total deferred credits and other liabilities	5,702	5,663
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$26,286	$25,707

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2007	2006	2005
Operating activities			
Net income	**$504**	$571	$697
Adjustments to reconcile net income to net cash provided by operating activities			
Impairment of assets	–	174	–
Charges for voluntary enhanced retirement program	–	–	159
Depreciation and amortization	**1,026**	1,190	1,216
Deferred income taxes and investment tax credits, net	**177**	(251)	(340)
Deferred fuel cost (credit)	**117**	396	(317)
Deferred income	**(128)**	(69)	–
Other adjustments to net income	**124**	88	135
Cash (used) provided by changes in operating assets and liabilities			
Receivables	**(193)**	78	(170)
Inventory	**(11)**	(168)	(163)
Prepayments and other current assets	**23**	(92)	(13)
Income taxes, net	**(275)**	197	101
Accounts payable	**(34)**	16	124
Other current liabilities	**150**	(30)	65
Other assets and deferred debits	**(221)**	(60)	(78)
Other liabilities and deferred credits	**(7)**	(39)	51
Net cash provided by operating activities	**1,252**	2,001	1,467
Investing activities			
Gross property additions	**(1,973)**	(1,572)	(1,313)
Nuclear fuel additions	**(228)**	(114)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**675**	1,657	475
Purchases of available-for-sale securities and other investments	**(1,413)**	(2,452)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	**1,452**	2,631	3,845
Other investing activities	**30**	(23)	(40)
Net cash (used) provided by investing activities	**(1,457)**	127	(1,144)
Financing activities			
Issuance of common stock	**151**	185	208
Dividends paid on common stock	**(627)**	(607)	(582)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	**176**	–	–
Net increase (decrease) in short-term debt	**25**	(175)	(509)
Proceeds from issuance of long-term debt, net	**739**	397	1,642
Retirement of long-term debt	**(324)**	(2,200)	(564)
Other financing activities	**55**	(68)	32
Net cash provided (used) by financing activities	**195**	(2,468)	227
Net (decrease) increase in cash and cash equivalents	**(10)**	(340)	550
Cash and cash equivalents at beginning of year	**265**	605	55
Cash and cash equivalents at end of year	**$255**	$265	$605
Supplemental disclosures			
Cash paid during the year			
Interest (net of amount capitalized)	**$585**	$698	$645
Income taxes (net of refunds)	**176**	311	168
Significant noncash transactions			
Capital lease obligation incurred	**182**	54	–
Note receivable for disposal of ownership interest in Ceredo	**48**	–	–
Noncash property additions accrued for as of December 31	**329**	231	116

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(in millions)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2004	247	$5,360	$(13)	$(76)	$(164)	$2,526	$7,633
Net income		–	–	–	–	697	697
Other comprehensive income		–	–	–	60	–	60
Comprehensive income							757
Issuance of shares	5	199	–	–	–	–	199
Presentation reclassification – SFAS No. 123R adoption		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		13	–	–	–	–	13
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	252	5,571	–	(63)	(104)	2,634	8,038
Net income		–	–	–	–	571	571
Other comprehensive loss		–	–	–	(18)	–	(18)
Comprehensive income							553
Adjustment to initially apply SFAS No. 158, net of tax		–	–	–	73	–	73
Issuance of shares	4	70	–	–	–	–	70
Stock options exercised		115	–	–	–	–	115
Purchase of restricted stock		(8)	–	–	–	–	(8)
Allocation of ESOP shares		13	–	13	–	–	26
Stock-based compensation expense		30	–	–	–	–	30
Dividends ($2.43 per share)		–	–	–	–	(611)	(611)
Balance, December 31, 2006	**256**	**5,791**	**–**	**(50)**	**(49)**	**2,594**	**8,286**
Net income		**–**	**–**	**–**	**–**	**504**	**504**
Other comprehensive income		**–**	**–**	**–**	**15**	**–**	**15**
Comprehensive income							**519**
Adjustment to initially apply FASB Interpretation No. 48		**–**	**–**	**–**	**–**	**(2)**	**(2)**
Issuance of shares	**4**	**46**	**–**	**–**	**–**	**–**	**46**
Stock options exercised		**105**	**–**	**–**	**–**	**–**	**105**
Allocation of ESOP shares		**15**	**–**	**13**	**–**	**–**	**28**
Stock-based compensation expense		**71**	**–**	**–**	**–**	**–**	**71**
Dividends ($2.45 per share)		**–**	**–**	**–**	**–**	**(631)**	**(631)**
Balance, December 31, 2007	**260**	**$6,028**	**$–**	**$(37)**	**$(34)**	**$2,465**	**$8,422**

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2007	2006	2005
Net income	**$504**	$571	$697
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax (expense) benefit of $(3), $28 and $(26), respectively)	**4**	(46)	46
Foreign currency translation adjustments included in discontinued operations	**–**	–	(6)
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	**–**	–	1
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $1)	**2**	–	–
Net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $8, $16 and $(26), respectively)	**(13)**	(23)	37
Net unrecognized items on pension and other postretirement benefits (net of tax expense of $16)	**23**	–	–
Minimum pension liability adjustment (net of tax (expense) benefit of $(30) and $22, respectively)	**–**	48	(19)
Other (net of tax benefit (expense) of $3, $- and $(1), respectively)	**(1)**	3	1
Other comprehensive income (loss)	**15**	(18)	60
Comprehensive income	**$519**	$553	$757

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

PEC and PEF are regulated public utilities primarily engaged in the generation, transmission, distribution and sale of electricity. 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) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies (generally 20 percent to 50 percent ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

These combined notes accompany and form an integral part of our consolidated financial statements.

Certain amounts for 2006 and 2005 have been reclassified to conform to the 2007 presentation. In addition, our 2007 presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, "Statement of Cash Flows." Previously, we had provided separate disclosure of cash flows from continuing operations and discontinued operations. These changes in cash flow presentations had no impact on total cash and cash equivalents, net change in cash and cash equivalents, or results of operations.

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable

Interest Entities – An Interpretation of ARB No. 51" (FIN 46R).

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2007, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $6 million, which represents our net remaining investment in the entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC 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). At December 31, 2007, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $39 million, $45 million and $44 million in 2007, 2006 and 2005, 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 power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in 21 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2007, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $19 million, which primarily represents its net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF has interests in four variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one limited liability corporation, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2007, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $56 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income on the Consolidated Statements of Income were $299 million, $293 million and $258 million for the years ended December 31, 2007, 2006 and 2005, respectively.

STOCK-BASED COMPENSATION

Prior to July 2005, we accounted for stock-based compensation under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for our stock-based compensation costs. In addition, we followed the disclosure requirements contained in SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." Effective July 1, 2005, we adopted the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), for stock-based compensation utilizing the modified prospective transition method (See Note 10B).

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations (ARO) under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), are charged to a regulatory liability.

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

ASSET RETIREMENT OBLIGATIONS

We account for AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. In addition, effective December 31, 2005, we also adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), which clarified certain requirements of SFAS No. 143.

The adoption of SFAS No. 143 and FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 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. The Clean Smokestacks Act froze North Carolina electric utility base rates for a five-year period, which ended in December 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 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. During 2007, the NCUC approved PEC's request to amortize the remaining 30 percent of the original estimated compliance costs during 2008 and 2009, with discretion to amortize up to $174 million in either year.

CASH AND CASH EQUIVALENTS

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

INVENTORY

We account for inventory, including emission allowances, using the average cost method. 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. We value inventory of nonregulated subsidiaries at the lower of cost or market.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

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

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies in accordance with SFAS No 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable 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

As discussed in Note 9, we account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

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

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by our subsidiaries are recorded in the Consolidated Statements of Income, except for any transactions that must be credited directly to equity in accordance with the provisions of Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. NEW ACCOUNTING STANDARDS

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"

Refer to Note 14 for information regarding our first quarter 2007 implementation of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which redefines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." SFAS No. 157 establishes a framework for measuring fair value and a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. The effective date of SFAS No. 157 for us is January 1, 2008. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, which for us delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. We will implement SFAS No. 157 as of January 1, 2008, and will utilize the deferral provision of FSP No. FAS 157-2 for all nonfinancial assets and liabilities within its scope. We do not expect the adoption of SFAS No. 157 to have a material impact on our financial position or results of operations.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115" (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied on an instrument by instrument basis, is irrevocable (unless a new election date occurs) and is applied to the entire financial instrument. SFAS No. 159 is effective for us on January 1, 2008. We do not expect the adoption of SFAS No. 159 to have a material impact on our financial position or results of operations.

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

FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" (FIN 39), specifies what conditions must be met for an entity to have the right to offset assets and liabilities in the balance sheet and clarifies when it is appropriate to offset amounts recognized for forward interest rate swap, currency swap option, and other conditional or exchange contracts. FIN 39 also permits offsetting of fair value amounts recognized for multiple contracts executed with the same counterparty under a master netting arrangement. On April 30, 2007, the FASB issued FASB Staff Position FIN No. 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), which amends portions of FIN 39 to make certain terms consistent with those used in SFAS No 133. FSP FIN 39-1 also amends FIN 39 to allow for the offsetting of fair value amounts for the right to reclaim collateral assets or liabilities arising from the same master netting arrangement as the derivative instruments. We will implement the FSP as of January 1, 2008, as a retrospective change in accounting principle for all financial statements presented. We currently offset fair value amounts recognized for derivative instruments under master netting arrangements. As allowed under FSP FIN 39-1, we will change our accounting policy effective January 1, 2008, and discontinue the offset of fair value amounts for such derivatives. We expect this change in policy to result in increases to total derivative assets and liabilities and accounts receivables and payables of $64 million as of adoption on January 1, 2008, but will have no impact on our results of operations or equity.

SFAS No. 141R, "Business Combinations"

In December 2007, the FASB issued SFAS Statement No. 141R, "Business Combinations" (SFAS No. 141R), which introduces significant changes in the accounting for business acquisitions. SFAS No. 141R considerably broadens the definition of a "business" and a "business combination," which will result in an increased number of transactions or other events that will qualify as business combinations. This will affect us primarily in our assessment of variable interest entities ("VIEs"). SFAS No. 141R amends FIN 46R to clarify that the initial consolidation of a business that is a VIE is a business combination in which the acquirer should recognize and measure the fair value of the acquiree as a whole, and the assets acquired and liabilities assumed at their full fair values as of the date control is obtained, regardless of the percentage ownership in the acquiree or how the acquisition was achieved. Other significant changes include the expensing of all acquisition-related transaction costs and most acquisition-related restructuring costs, the fair value remeasurement of certain earn-out arrangements and the discontinuance of the expense at acquisition of acquired-in-process research and development. SFAS No. 141R is effective for us for business combinations for which the acquisition date is on or after January 1, 2009. Earlier application is prohibited. We do not expect the adoption of SFAS No. 141R to have a material impact on our financial position or results of operations.

SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51"

In conjunction with the issuance of SFAS No. 141R, in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" (SFAS No. 160) which introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. SFAS No. 160 also changes the accounting for and reporting for the deconsolidation of a subsidiary. SFAS No. 160 requires that a noncontrolling interest in a consolidated subsidiary be displayed in the consolidated statement of financial position as a separate component of equity rather than as a "mezzanine" item between liabilities and equity. SFAS No. 160 also requires that earnings attributed to the noncontrolling interests be reported as part of consolidated earnings, and requires disclosure of the attribution of consolidated earnings to the controlling and noncontrolling interests on the face of the consolidated income statement. SFAS No. 160 must be adopted concurrently with the effective date of SFAS No. 141R, which for us is January 1, 2009. We do not expect the adoption of SFAS No. 160 to have a material impact on our financial position or results of operations.

3. DIVESTITURES

A. CCO – Georgia Operations

On March 9, 2007, our subsidiary, Progress Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested include approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the year ended December 31, 2007, we reversed $18 million after-tax of the impairment recorded in 2006.

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 represents 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 represents the net cost to assign the Georgia Contracts and other related contracts. In the year ended December 31, 2007, we recorded a charge associated with the costs to exit the Georgia Contracts, and other related contracts, of $349 million after-tax (charge included in the net loss from discontinued operations in the table below). We used the net proceeds from the divestiture of CCO and the Georgia Contracts for general corporate purposes.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $11 million, $36 million and $39 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during each of the years ended December 31, 2006 and 2005 was $14 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$407**	$754	$627
Loss before income taxes	**$(449)**	$(92)	$(93)
Income tax benefit	**166**	35	39
Net loss from discontinued operations	**(283)**	(57)	(54)
Gain (loss) on disposal of discontinued operations, including income tax benefit of $7 and $123, respectively	**18**	(226)	–
Loss from discontinued operations	**$(265)**	$(283)	$(54)

B. Terminals Operations and Synthetic Fuels Businesses

On December 24, 2007, we signed an agreement to sell coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. Terminals was previously a component of our former Coal and Synthetic Fuels segment. The terminals have a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale are expected to be used for general corporate purposes. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Terminals as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during each of the years ended December 31, 2007, 2006 and 2005 was $2 million, $4 million and $7 million, respectively.

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels (Synthetic Fuels) as defined under Section 29 of the Code. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Synthetic fuels are generally not economical to produce and sell absent the credits. On September 14, 2007, we idled production of synthetic fuels at our majority-owned synthetic fuels facilities due to the high level of oil prices. On October 12, 2007, based upon the continued high level of oil prices, unfavorable oil price projections through the end of 2007, and the expiration of the synthetic fuels tax credit program at the end of 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. 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. In accordance with the provisions of SFAS No. 144, a long-lived asset is abandoned when it ceases to be used. The accompanying consolidated income statements have been restated for all periods presented to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Results of discontinued operations for the years ended December 31 for Terminals and Synthetic Fuels were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$1,126**	$847	$1,220
Earnings (loss) before income taxes and minority interest	**$2**	$(179)	$(171)
Income tax benefit including tax credits	**64**	135	336
Minority interest share of losses	**17**	7	33
Net earnings (loss) from discontinued operations	**$83**	$(37)	$198

C. Natural Gas Drilling and Production

On October 2, 2006, we sold our natural gas drilling and production business (Gas) for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2006, and 2005 was $13 million. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $16 million and $26 million, respectively. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	$–	$192	$159
Earnings before income taxes	$–	$135	$73
Income tax benefit (expense)	4	(53)	(25)
Net earnings from discontinued operations	4	82	48
(Loss) gain on disposal of discontinued operations, including income tax benefit (expense) of $1 and $(188), respectively	(2)	300	–
Earnings from discontinued operations	$2	$382	$48

D. CCO – DeSoto and Rowan Generation Facilities

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

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2006, and 2005 was $6 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $3 million and $8 million, respectively. Results of discontinued operations for DeSoto and Rowan for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$64	$67
Earnings before income taxes	$15	$5
Income tax expense	(5)	(2)
Net earnings from discontinued operations	10	3
Loss on disposal of discontinued operations, including income tax benefit of $37	(67)	–
(Loss) earnings from discontinued operations	$(57)	$3

E. Progress Telecom, LLC

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

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax net gain on disposal of $28 million during the year ended December 31, 2006

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for the year ended December 31, 2005. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $8 million, respectively. Results of discontinued operations for PT LLC for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$18	$76
Earnings before income taxes and minority interest	$7	$11
Income tax expense	(4)	(3)
Minority interest share of earnings	(5)	(4)
Net (loss) earnings from discontinued operations	(2)	4
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35	28	–
Earnings from discontinued operations	$26	$4

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

F. Dixie Fuels and Other Fuels Business

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the year ended December 31, 2007, we recorded an additional gain of $2 million primarily related to the expiration of indemnifications

The accompanying consolidated financial statements reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $1 million for each of the years ended December 31, 2006, and 2005. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, and 2005 was $1 million and $2 million, respectively. Results of discontinued operations for Dixie Fuels and other fuels businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	$–	$20	$32
Earnings before income taxes	$–	$11	$8
Income tax expense	–	(4)	(3)
Net earnings from discontinued operations	–	7	5
Gain on disposal of discontinued operations, including income tax expense of $1 and $1, respectively	2	2	–
Earnings from discontinued operations	$2	$9	$5

G. Coal Mining Businesses

Progress Fuels owned five subsidiaries engaged in the coal mining business. These businesses were previously included in our former Coal and Synthetic Fuels business segment. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets.

On December 24, 2007, we signed an agreement to sell the remaining net assets of the coal mining business for gross cash proceeds of $23 million. These assets include Powell Mountain Coal Co. and Dulcimer Land Co., which consist of about 30,000 acres in Lee County, Va. and Harlan County, Ky. The property contains an estimated 40 million tons of high quality coal reserves. We expect this transaction to close by the end of the first quarter of 2008.

The accompanying consolidated financial statements reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007, 2006 and 2005 was $1 million, $1 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the year ended December 31, 2005, was $10 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Revenues	**$28**	$84	$184
Loss before income taxes	**$(17)**	$(11)	$(16)
Income tax benefit	**6**	7	5
Net loss from discontinued operations	**(11)**	(4)	(11)
Loss on disposal of discontinued operations, including income tax benefit of $16	**–**	(10)	–
Loss from discontinued operations	**$(11)**	$(14)	$(11)

H. Progress Rail

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt.

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

The accompanying consolidated financial statements reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the year ended December 31, 2005, was $4 million.

We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the year ended December 31, 2005, was $3 million. Results of discontinued operations for Progress Rail for the years ended December 31 were as follows:

(in millions)	2006	2005
Revenues	$–	$358
Earnings before income taxes	$–	$8
Income tax expense	–	(3)
Net earnings from discontinued operations	–	5
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	(6)	(25)
Loss from discontinued operations	$(6)	$(20)

I. Net Assets to be Divested

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of the coal mining operations were included in net assets to be divested. At December 31, 2006, the assets and liabilities of CCO, Terminals, the remaining coal mining operations and other fuels businesses were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2007**	December 31, 2006
Accounts receivable	**$–**	$44
Inventory	**6**	56
Other current assets	**2**	45
Property, plant and equipment, net	**38**	595
Other assets	**6**	226
Assets to be divested	**$52**	$966
Accounts payable	**$–**	$43
Accrued expenses	**3**	179
Long-term liabilities	**5**	26
Liabilities to be divested	**$8**	$248

J. Ceredo Synthetic Fuels Interests

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo Synfuel LLC (Ceredo), a subsidiary that produces and sells 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 non-recourse note receivable of $54 million. Payments on the note are due as we produce and sell qualifying 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 in 2007 and $5 million in 2008. The total amount of proceeds is subject to adjustment once the final value of the 2007 Section 29/45K credits is known. The note bears interest at a rate equal to the three-month London Inter Bank Offering Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million.

Pursuant to the terms of the disposal agreement, the buyer had the right to unwind the transaction if an Internal Revenue Service (IRS) reconfirmation private letter ruling was not received by November 9, 2007, or if certain adverse changes in tax law, as defined in the agreement, occurred before November 19, 2007. The IRS reconfirmation private letter ruling was received on October 29, 2007, and no adverse change in tax law occurred prior to November 19, 2007. As of December 31, 2007, due to indemnification provisions discussed below, we recorded losses on disposal of $3 million based on the estimated value of the 2007 Section 29/45K tax credits. The operations of Ceredo have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

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 remained the primary beneficiary of Ceredo and continued to consolidate Ceredo in accordance with FIN 46R, but recorded a 100 percent minority interest. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

K. Winter Park Distribution Assets

As discussed in Note 7C, PEF sold certain electric distribution assets to Winter Park, Fla. (Winter Park), on June 1, 2005.

L. Synthetic Fuels Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million and $30 million in the years ended December 31, 2006, and 2005, respectively. In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gains. The operations of Colona have been reclassified to discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3B.

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3C).

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	Depreciable Lives	2007	2006
Production plant	7-43	**$13,765**	$12,685
Transmission plant	17-75	**2,684**	2,509
Distribution plant	13-55	**7,676**	7,351
General plant and other	5-35	**1,202**	1,198
Utility plant in service		**$25,327**	$23,743

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12C)

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant 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 8.8%, 8.7% and 5.6% in 2007, 2006 and 2005, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8%, 8.8% and 7.8% in 2007, 2006 and 2005, respectively.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.2% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $560 million, $533 million and $477 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2007, 2006 and 2005 was $139 million, $140 million and $136 million, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.1% for 2007, 2006 and 2005. The depreciation provisions related to utility plant were $303 million, $294 million and $286 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Note 7B) and Clean Smokestacks Act amortization (See Note 7B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7%, 2.7% and 2.3% in 2007, 2006 and 2005, respectively. The depreciation provisions related to utility plant were $257 million, $239 million and $191 million in 2007, 2006 and 2005, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 21).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2007, 2006 and 2005 was $110 million, $109 million and $107 million, respectively, for PEC and $29 million, $31 million and $29 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets. Diversified business property excludes amounts reclassified as assets to be divested (See Note 3I)

The balances of diversified business property at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	2007	2006
Equipment (3-25 years)	$6	$10
Land and mineral rights	–	1
Buildings and plants (5-40 years)	9	47
Accumulated depreciation	(9)	(50)
Diversified business property, net	$6	$8

Diversified business depreciation expense was $3 million, $2 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the above jointly owned generating facilities is included within the corresponding line in the 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:

2007

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	**Mayo**	**83.83%**	**$519**	**$270**	**$128**
PEC	**Harris**	**83.83%**	**3,175**	**1,581**	**21**
PEC	**Brunswick**	**81.67%**	**1,647**	**959**	**16**
PEC	**Roxboro Unit 4**	**87.06%**	**634**	**164**	**39**
PEF	**Crystal River Unit 3**	**91.78%**	**817**	**450**	**177**
PEF	**Intercession City Unit P11**	**66.67%**	**23**	**9**	**–**

2006

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$517	$263	$–
PEC	Harris	83.83%	3,159	1,489	18
PEC	Brunswick	81.67%	1,632	941	15
PEC	Roxboro Unit 4	87.06%	356	163	1
PEF	Crystal River Unit 3	91.78%	811	452	76
PEF	Intercession City Unit P11	66.67%	23	7	–

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

D. Asset Retirement Obligations

At December 31, 2007 and 2006, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $150 million and $156 million, respectively. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.384 billion and $1.287 billion at December 31, 2007 and 2006, respectively. Net nuclear decommissioning trust 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 2007, 2006 and 2005. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 AROs, which are included in depreciation and amortization expense, were $126 million, $123 million and $168 million in 2007, 2006 and 2005, respectively.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006.

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

(in millions)	2007	2006
Removal costs	$1,410	$1,341
Nonirradiated decommissioning costs	141	137
Dismantlement costs	125	124
Non-ARO cost of removal	$1,676	$1,602

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2 and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. NRC operating licenses held by PEC currently expire in July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. We expect to submit an application requesting a 20-year extension of this license in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. PEF's reserve for fossil plant dismantlement was approximately $146 million and $145 million at December 31, 2007 and 2006, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 1D).

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

Our nonregulated AROs relate to our abandoned synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $1 million at December 31, 2006, and none at December 31, 2007

The following table presents the changes to the AROs during the years ended December 31, 2007 and 2006. Revisions to prior estimates of the PEC regulated ARO are related to remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above

(in millions)	Regulated	Nonregulated
Asset retirement obligations at January 1, 2006	$1,239	$–
Accretion expense	72	–
Remediation	(2)	1
Revisions to prior estimates	(6)	–
Asset retirement obligations at December 31, 2006	1,303	1
Accretion expense	**75**	**–**
Remediation	**–**	**(1)**
Asset retirement obligations at December 31, 2007	**$1,378**	**$–**

E. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1 750 billion on each nuclear plant

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River Plant An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $34 million with respect to the primary coverage, $37 million with respect to the decontamination, decommissioning and excess property coverage, and $24 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.760 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from 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 $100 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 $15 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 31, 2008.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion for non-certified 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)

6. CURRENT ASSETS

A. Receivables

Income tax receivables and interest income receivables are not included in receivables. These amounts are included in prepaids and other current assets on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

(in millions)	2007	2006
Trade accounts receivable	**$586**	$628
Unbilled accounts receivable	**220**	227
Notes receivable	**67**	57
Derivative accounts receivable	**247**	–
Other receivables	**46**	46
Allowance for doubtful receivables	**(29)**	(28)
Total receivables	**$1,137**	$930

B. Inventory

At December 31 inventory was comprised of:

(in millions)	2007	2006
Fuel for production	**$455**	$470
Inventory for sale	–	2
Materials and supplies	**520**	442
Emission allowances	**19**	22
Total inventory	**$994**	$936

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits of $65 million and $44 million at December 31, 2007 and 2006, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits of $32 million at December 31, 2007. Progress Energy did not have any long-term emission allowance amounts at December 31, 2006.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of SFAS No 71. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of SFAS No. 71 could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

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

(in millions)	2007	2006
Deferred fuel cost – current (Note 7B)	**$154**	$196
Deferred fuel cost – long-term (Note 7B)	**114**	114
Deferred impact of ARO – PEC (Note 1D)	**294**	282
Income taxes recoverable through future rates (Note 14)	**141**	114
Loss on reacquired debt (Note 1D)	**43**	46
Storm deferral (Notes 7B and 7C)	**22**	102
Postretirement benefits (Note 16)	**212**	373
Derivative mark-to-market adjustment (Note 17A)	–	78
Environmental (Notes 7B, 7C and 21A)	**40**	72
Investment in GridSouth (Note 7D)	**22**	–
Other	**43**	50
Total long-term regulatory assets	**931**	1,231
Deferred fuel cost – current (Note 7C)	**(154)**	(63)
Deferred energy conservation cost and other current regulatory liabilities	**(19)**	(13)
Total current regulatory liabilities	**(173)**	(76)
Non-ARO cost of removal (Note 5D)	**(1,676)**	(1,602)
Deferred impact of ARO – PEF (Note 1D)	**(226)**	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(351)**	(330)
Clean Smokestacks Act compliance (Note 7B)	–	(333)
Derivative mark-to-market adjustment (Note 17A)	**(185)**	–
Storm reserve (Note 7C)	**(63)**	(2)
Other	**(38)**	(55)
Total long-term regulatory liabilities	**(2,539)**	(2,543)
Net regulatory liabilities	**$(1,627)**	$(1,192)

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We anticipate recovering long-term deferred fuel costs in 2009 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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 (ROE) of 12.75 percent. In June 2002, the North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxides (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 significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. For the years ended December 31, 2007, 2006 and 2005, PEC recognized amortization of $34 million, $140 million and $147 million, respectively, and recognized $569 million in cumulative amortization through December 31, 2007.

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Associations (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. The NCUC held a hearing on this matter on October 30, 2007. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated costs of $813 million. Additionally, the NCUC ordered that no portion of Clean Smokestacks Act compliance costs directly assigned, allocated or otherwise attributable to another jurisdiction shall be recovered from PEC's retail North Carolina customers, even if recovery of these costs is disallowed or denied, in whole or in part, in another jurisdiction. We cannot predict the outcome of PEC's recovery of eligible compliance costs exceeding the original estimated compliance costs.

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

FUEL COST RECOVERY

On May 2, 2007, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $12 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 27, 2007, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceedings. The settlement agreement resolved all issues and provided for a $12 million increase in fuel rates. Effective July 1, 2007, residential electric bills increased by $1.83 per 1,000 kilowatt-hours (kWh), or 1.9 percent, for fuel cost recovery. At December 31, 2007, PEC's South Carolina deferred fuel balance was $21 million.

On June 8, 2007, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. PEC asked the NCUC to approve a $48 million increase in fuel rates. On September 25, 2007, the NCUC approved PEC's petition. The increase took effect October 1, 2007, and increased residential electric bills by $1.30 per 1,000 kWh, or 1.3 percent, for fuel cost recovery. This was the second increase associated with a three-year settlement approved by the NCUC in 2006. The settlement provided for an increase of $177 million effective October 1, 2006; $48 million effective October 1, 2007, as discussed above; and an additional increase of approximately $30 million in October 2008. On November 21, 2006, CUCA filed an appeal with the North Carolina Tenth District Court of Appeals of the NCUC's order approving the settlement on the grounds that the NCUC did not have the statutory authority to establish fuel rates for more than one year On October 24, 2007, CUCA filed a motion to withdraw their appeal. On November 7, 2007, the North Carolina Tenth District Court of Appeals granted CUCA's motion. At December 31, 2007, PEC's North Carolina deferred fuel balance was $241 million, of which $114 million is expected to be collected after 2008 and has been classified as a long-term regulatory asset.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. For the years ended December 31, 2007, 2006 and 2005, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize the respective jurisdictional portion of $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense. During the year ended December 31, 2007, PEC recorded $3 million of amortization expense. Additionally, PEC reduced the regulatory asset by $2 million during the year ended December 31, 2007, based on newly available data regarding certain remediation sites and insurance proceeds (See Note 21A).

The NCUC and SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively, 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 $37 million in 2007. No additional depreciation expense from accelerated cost recovery was recorded in 2006 or 2005. Through December 31, 2007, PEC recorded total accelerated depreciation of $440 million, of which $363 million was recorded for the North Carolina jurisdiction and $77 million was recorded for the South Carolina jurisdiction.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of new demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs that are 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 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 and interruptible load. PEC has begun implementing a series of DSM and energy-efficiency programs and deferred $2 million of implementation and program costs through December 31, 2007, for future recovery.

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred an immaterial amount of implementation and program costs through December 31, 2007, for future recovery in the South Carolina jurisdiction. PEC anticipates applying for a DSM and energy-efficiency clause to recover the costs of these programs in 2008. We cannot predict the outcome of this matter.

C. PEF Retail Rate Matters

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2007 threshold of $1.537 billion and thus no revenues were subject to revenue sharing. Both the 2007 base threshold of $1.537 billion and the 2007 cap of $1.588 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. PEF's 2006 retail base rates did not exceed the threshold and no revenues were subject to the revenue sharing provisions. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent ROE for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase

PASS-THROUGH CLAUSE COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. PEF asked the FPSC to approve a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008. This cost adjustment would decrease residential bills by $5.00 for the first 1,000 kWh. As discussed above, residential base rates increased due to specified generation facilities placed in service in 2007 by $2.73 for the first 1,000 kWh effective January 1, 2008. After considering the net effect of the base rate increase and the proposed fuel cost adjustment, 2008 residential bills would decrease by a net amount of $2.27 for the first 1,000 kWh. The FPSC approved the cost-recovery rates for 2008 in an order dated January 8, 2008. At December 31, 2007, PEF's current regulatory liabilities totaled $173 million, which were comprised of over-recovered fuel and capacity costs of $140 million, accrued disallowed fuel costs of $14 million, over-recovered conservation costs of $14 million and over-recovered environmental compliance of $5 million

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On July 31, 2007, the FPSC heard this matter. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the 4-1 majority found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. On October 25, 2007, the OPC requested the FPSC to reconsider its October 10, 2007 order asserting that the FPSC erred in not ordering a larger refund. PEF filed its opposition to the OPC's request on November 1, 2007. On February 12, 2008, the FPSC denied the OPC's request for reconsideration. PEF is also evaluating its options, including an appeal to the Florida Supreme Court of the FPSC's October 10, 2007 order. We cannot predict the outcome of this matter. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. The OPC filed testimony in support of its position to require PEF to refund at least $14 million for alleged excessive fuel recovery charges for 2006 coal purchases. PEF believes its coal procurement practices have been prudent. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3, bid rule exemption and recovery of the revenue requirements of the uprate through PEF's fuel recovery clause. To the extent the expenditures are prudently incurred, PEF's investment in the CR3 uprate is eligible for recovery through base rates. PEF's petition would allow for more prompt recovery. The multi-stage uprate will increase CR3's gross output by approximately 180 MW by 2012. PEF received NRC approval for a license amendment and implemented the first stage's design modification on January 31, 2008, and will apply for the required license amendment for the third stage's design modification. The petition filed with the FPSC included estimated project costs of approximately $382 million. These cost estimates may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. On March 27, 2007, the FPSC denied the motion to abate and directed the staff of the FPSC to conduct a hearing to determine whether the revenue requirements of the uprate should be recovered through the fuel recovery clause. On May 4, 2007, PEF filed amended testimony clarifying the scope of the project. The FPSC held a hearing on this matter on August 7 and 8, 2007. The staff of the FPSC recommended that PEF be allowed to recover prudent and reasonable costs of Phase 1, estimated at $6 million, through the fuel clause. The staff of the FPSC recommended that the costs of all other phases, estimated at $376 million, be considered in a base rate proceeding. On October 19, 2007, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. On November 21, 2007, PEF filed a petition with the FPSC seeking cost recovery under Florida's comprehensive energy bill enacted in 2006, and the FPSC's new nuclear cost-recovery rule. On February 13, 2008, PEF filed a notice of withdrawal of its cost-recovery petition with the FPSC. PEF will proceed with cost recovery under Florida's comprehensive energy bill and the FPSC's nuclear cost-recovery rule based on the regulatory precedence established by a FPSC order to an unaffiliated Florida utility for a nuclear uprate project. We cannot predict the outcome of this matter.

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWh beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as O&M expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006. In 2007, 2006 and 2005, PEF recorded amortization of $75 million, $122 million and $50 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately

$3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which began August 2007, is expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified. Through December 31, 2007, PEF had recorded an additional $55 million of storm reserve from the extension of the storm surcharge. At December 31, 2007, PEF's storm reserve totaled $63 million.

FRANCHISE MATTERS

On June 1, 2005, Winter Park acquired PEF's electric distribution system that serves Winter Park for approximately $42 million. On June 1, 2005, PEF transferred the distribution system to Winter Park and recognized a pre-tax gain of approximately $25 million on the transaction, which is included as an offset to other utility expense on the Statements of Income. This amount was decreased $1 million in the third quarter of 2005 upon accumulation of the final capital expenditures incurred since arbitration. PEF also recorded a regulatory liability of $8 million for stranded cost revenues, which will be amortized to revenues over six years in accordance with the provisions of the transfer agreement with Winter Park. In June 2004, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent. PEF received FERC approval of the settlement agreement on December 17, 2007. The new rates were effective January 1, 2008, and PEF estimates the impact of the new rates will increase 2008 revenues by $1 million to $2 million.

D. Regional Transmission Organizations

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (RTOs) must meet, including independent transmission service. In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth Transco, LLC (GridSouth). In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO. PEC participated in the mediation; no consensus was reached on creating a southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding.

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Until the NCUC rules upon PEC's petition, PEC will apply the same accounting treatment to its GridSouth development costs. Consequently, in December 2007, PEC recorded an $11 million charge to amortization expense to reduce the North Carolina portion of development costs, which is included in depreciation and amortization on the Consolidated Statements of Income. PEC's recorded investment in GridSouth totaled $22 million and $33 million at December 31, 2007 and 2006. PEC expects to recover its GridSouth development costs based on precedent regulatory proceedings; in 2007, PEC reclassified its investment in GridSouth from other assets and deferred debits to regulatory assets on the Consolidated Balance Sheets. We cannot predict the outcome of this matter.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

E. Nuclear License Renewals

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved. PEC anticipates a decision from the NRC in 2008. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF expects to submit an application requesting a 20-year extension of this license in the first quarter of 2009.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2007 and 2006; each test indicated no impairment. Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill impairment tests were performed at our CCO-Georgia Operations reporting unit level, which was comprised of four nonregulated generating plants (Georgia Operations). As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed the annual goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3A).

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented the entirety of the synthetic fuels intangible assets; these assets had been reported within our former Coal and Synthetic Fuels segment (See Note 3B).

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2006, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million, of which $64 million has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

A. Long-Lived Assets

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income, as discussed in Note 3B. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within our former Coal and Synthetic Fuels segment. There were no impairments of long-lived assets in 2007.

B. Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. There were no other-than-temporary impairments in 2007. As a result of various factors, including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million on a pre-tax basis in both 2006 and 2005.

10. EQUITY

A. Common Stock

At December 31, 2007 and 2006, we had 500 million shares of common stock authorized under our charter, of which 260 million shares and 256 million shares, respectively, were outstanding. During 2007, 2006 and 2005, respectively, we issued approximately 3.4 million, 4.2 million and 4.8 million shares of common stock, resulting in approximately $151 million, $185 million and $208 million in proceeds. Included in these amounts for 2007, 2006 and 2005, respectively, were approximately 1.0 million, 1.6 million and 4.6 million shares for proceeds of approximately $46 million, $70 million and $199 million, to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan.

At December 31, 2007 and 2006, we had approximately 50 million shares and 54 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2007, there were no significant restrictions on the use of retained earnings (See Note 12).

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, 2007 and 2006, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 1.7 million and 2.3 million ESOP suspense shares at December 31, 2007 and 2006, respectively, with a fair value of $82 million and $112 million, respectively. ESOP shares allocated to plan participants totaled 10.6 million and 10.9 million at December 31, 2007 and 2006, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $23 million, $14 million and $18 million for the years ended December 31, 2007, 2006 and 2005, respectively. Total matching and incentive costs were approximately $30 million, $23 million and $30 million for the years ended December 31, 2007, 2006 and 2005, respectively We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

Effective January 1, 2008, the 401(k) was revised. As revised, the employer match percentage was increased and the employee stock incentive plan based on goal attainment was discontinued.

STOCK OPTIONS

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

A summary of the status of our stock options at December 31, 2007, 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	4.0	$43.70
Canceled	–	45.55
Exercised	(2.3)	43.47
Options outstanding, December 31	1.7	43.99
Options exercisable, December 31	1.7	43.99

The options outstanding and exercisable at December 31, 2007, had a weighted-average remaining contractual life of 5.0 years and an aggregate intrinsic value of $8 million. Total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005, respectively, was $17 million, $10 million and less than $1 million.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the grant date using a Black-Scholes option pricing model. Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

As of December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2007. Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year. Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income and earnings per share if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions except per share data)	2005
Net income, as reported	$697
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2
Pro forma net income	$695
Earnings per share	
Basic – as reported	$2.82
Basic – pro forma	2.81
Diluted – as reported	2.82
Diluted – pro forma	2.81

Cash received from the exercise of stock options totaled $105 million, $115 million and $8 million, respectively, during the years ended December 31, 2007, 2006 and 2005. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2005, 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 of which were based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities totaling $3 million, $4 million and $5 million were paid in the years ended December 31, 2007, 2006 and 2005, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2007, 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	1,044,583	$44.26
Granted	892,410	50.70
Paid[b]	(190,567)	50.70
Forfeited	(116,431)	44.84
Ending balance	1,629,995	$44.97

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.
[b] Shares paid include only target shares as originally granted. Additional shares of 106,478 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.27 and $44.24, respectively.

The Restricted Stock Award (RSA) program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2007, and changes during the year then ended, is presented below

For the years ended December 31, 2006 and 2005, the weighted-average grant date fair value of restricted stock granted was $44.51 and $42.56, respectively.

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	604,238	$43.82
Granted	7,000	49.54
Vested	(303,935)	44.08
Forfeited	(38,668)	43.16
Ending balance	268,635	$43.77

The total fair value of restricted stock awards vested during the years ended December 31, 2007, 2006 and 2005 was $13 million, $4 million and $7 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the years ended December 31, 2006 and 2005, respectively. Cash expended to purchase shares for 2007 was not significant due to the curtailment of the RSA program and the rollout of the new restricted stock unit (RSU) program.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers, and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. 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. RSUs are not included as shares outstanding in the basic earnings per share calculation until shares are no longer forfeitable. Units are converted to shares upon vesting. A summary of the status of nonvested RSUs at December 31, 2007, and changes during the year then ended, is presented below:

	Number of Restricted Units	Weighted-Average Grant Date Fair Value
Beginning balance	–	$–
Granted	913,282	50.33
Vested	(49,430)	50.70
Forfeited	(39,394)	50.70
Ending balance	824,458	$50.29

The total fair value of RSUs vested during the year ended December 31, 2007, was $3 million. There were no expenditures to purchase stock to satisfy RSU plan obligations in 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $70 million for the year ended December 31, 2007, with a recognized tax benefit of $27 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $25 million with a recognized tax benefit of $10 million and $10 million, with a recognized tax benefit of $4 million, for the years ended December 31, 2006 and 2005, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2007, there was $51 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 1.8 years.

C. Earnings per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effects of the nonvested portion of restricted stock, restricted stock unit awards and performance share awards and the effect of stock options outstanding.

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

(in millions)	**2007**	2006	2005
Weighted-average common shares – basic	**256.1**	250.4	246.6
Net effect of dilutive stock-based compensation plans	**0.6**	0.4	0.4
Weighted-average shares – fully diluted	**256.7**	250.8	247.0

There were no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 1.8 million, 2.4 million and 3.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. There were 0.1 million, 1.8 million and 2.9 million stock options outstanding at December 31, 2007, 2006 and 2005, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

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

(in millions)	**2007**	2006
Loss on cash flow hedges	**$(23)**	$(14)
Pension and other postretirement benefits	**(13)**	(39)
Other	**2**	4
Total accumulated other comprehensive loss	**$(34)**	$(49)

11. PREFERRED STOCK OF SUBSIDIARIES – NOT SUBJECT TO MANDATORY REDEMPTION

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2007 and 2006, preferred stock outstanding consisted of the following:

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

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2007)

(in millions)		2007	2006
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	$2,600	$2,600
Unamortized fair value hedge gain, net		–	(1)
Unamortized premium and discount, net		(3)	(18)
Long-term debt, net		2,597	2,581
PEC			
First mortgage bonds, maturing 2009-2035	5.65%	2,000	2,200
Pollution control obligations, maturing 2017-2024	4.57%	669	669
Senior unsecured notes, maturing 2012	6.50%	500	500
Medium-term notes, maturing 2008	6.65%	300	300
Miscellaneous notes		22	22
Unamortized premium and discount, net		(8)	(21)
Current portion of long-term debt		(300)	(200)
Long-term debt, net		3,183	3,470
PEF			
First mortgage bonds, maturing 2008-2037	5.64%	2,380	1,630
Pollution control obligations, maturing 2018-2027	4.32%	241	241
Senior unsecured notes, maturing 2008	5.27%	450	450
Medium-term notes, maturing 2008-2028	6.75%	152	241
Unamortized premium and discount, net		(5)	(5)
Current portion of long-term debt		(532)	(89)
Long-term debt, net		2,686	2,468
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	309	309
Unamortized premium and discount, net		(38)	(38)
Long-term debt, net		271	271
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2008	6.46%	45	80
Current portion of long-term debt		(45)	(35)
Long-term debt, net		–	45
Progress Energy consolidated long-term debt, net		$8,737	$8,835

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.

At December 31, 2007 and 2006, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2007 and 2006, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2007:

(in millions)	Description	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc	Five-year (expiring 5/3/11)	$1,130	$–	$220	$910
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$–	$220	$1,810

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2007, Progress Energy, Inc. had a total amount of $19 million of letters of credit issued, which were supported by the RCA.

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

Our outstanding commercial paper and other short-term debt and related weighted-average interest rate at December 31, 2007, was $201 million and 5.48%, respectively.

We had no commercial paper outstanding or other short-term debt at December 31, 2006.

The following table presents the aggregate maturities of long-term debt at December 31, 2007:

(in millions)	
2008	$877
2009	400
2010	406
2011	1,000
2012	950
Thereafter	6,035
Total	$9,668

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2007, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Progress Energy, Inc.	68%	54.4%
PEC	65%	48.8%
PEF	65%	53.2%

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

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for Progress Energy, Inc. and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision can be triggered by Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement, (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions can only be triggered 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 Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $2.6 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'s Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2007, Progress Energy, Inc. had no shares of preferred stock outstanding. Certain documents restrict the payment of dividends by Progress Energy, Inc.'s subsidiaries as outlined below.

PEC'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, 2007, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2007, PEC's common stock equity was approximately 53.8 percent of total capitalization. At December 31, 2007, 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, 2007, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2007, PEF's common stock equity was approximately 52.5 percent of total capitalization. At December 31, 2007, 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, 2007, PEC and PEF had a total of $2.669 billion and $2.621 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

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

E. Hedging Activities

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

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2007 and 2006, 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)	**2007**	2006
Nuclear decommissioning trust (See Note 5D)	**$1,384**	$1,287
Investments in equity securities[a]	**–**	5
Equity method investments[b]	**23**	24
Cost investments[c]	**8**	8
Benefit investment trusts[d]	**82**	80
Company-owned life insurance[d]	**168**	161
Marketable debt securities[e]	**1**	71
Total	**$1,666**	$1,636

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(b) Investments in unconsolidated companies are included in miscellaneous other property and investments in the Consolidated Balance Sheets using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20).

(c) Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(d) Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.

(e) We actively invest available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As we intend to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

DEBT

The carrying amount of our long-term debt, including current maturities, was $9.614 billion and $9.159 billion at December 31, 2007 and 2006, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.897 billion and $9.543 billion at December 31, 2007 and 2006, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2007 and 2006 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2007 *(in millions)*	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$465**	**$354**	**$819**
Debt securities	**574**	**11**	**585**
Cash equivalents	**18**	**–**	**18**
Total	**$1,057**	**$365**	**$1,422**
2006 *(in millions)*	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$428	$324	$752
Debt securities	606	13	619
Cash equivalents	19	–	19
Total	$1,053	$337	$1,390

At December 31, 2007, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$8
Due after one through five years	145
Due after five through 10 years	198
Due after 10 years	234
Total	$585

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2007**	2006	2005
Proceeds	**$1,334**	$2,547	$3,755
Realized gains	**35**	33	26
Realized losses	**37**	24	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2007 and 2006 for investments in these trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2007 and 2006, our other securities had no investments in a continuous loss position for greater than 12 months.

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. 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)	**2007**	2006
Deferred income tax assets		
Asset retirement obligation liability	**$146**	$141
Compensation accruals	**101**	86
Deferred revenue	**–**	28
Derivative instruments	**–**	42
Environmental remediation liability	**32**	36
Income taxes refundable through future rates	**317**	216
Investments	**–**	28
Pension and other postretirement benefits	**306**	364
Unbilled revenue	**41**	36
Other	**122**	103
Federal income tax credit carry forward	**836**	851
State net operating loss carry forward (net of federal expense)	**87**	54
Valuation allowance	**(79)**	(71)
Total deferred income tax assets	**1,909**	1,914
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,482)**	(1,379)
Deferred fuel recovery	**(64)**	(60)
Deferred storm costs	**(6)**	(51)
Derivative instruments	**(59)**	–
Income taxes recoverable through future rates	**(384)**	(436)
Investments	**(25)**	–
Prepaid pension costs	**(18)**	–
Other	**(50)**	(66)
Total deferred income tax liabilities	**(2,088)**	(1,992)
Total net deferred income tax liabilities	**$(179)**	$(78)

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

(in millions)	**2007**	2006
Current deferred income tax assets	**$27**	$142
Noncurrent deferred income tax assets, included in other assets and deferred debits	**65**	17
Current deferred income tax liabilities, included in other current liabilities	**(5)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(266)**	(237)
Total net deferred income tax liabilities	**$(179)**	$(78)

At December 31, 2007, the federal income tax credit carry forward includes $772 million of alternative minimum tax credits that do not expire and $64 million of general business credits that will expire during the period 2020 through 2027.

At December 31, 2007, we had gross state net operating loss carry forwards of $1.9 billion that will expire during the period 2008 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $8 million during 2007. 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:

	2007	2006	2005
Effective income tax rate	32.3%	37.5%	36.1%
State income taxes, net of federal benefit	(2.8)	(3.5)	(3.5)
Investment tax credit amortization	1.1	1.3	1.6
Employee stock ownership plan dividends	1.1	1.3	1.5
Domestic manufacturing deduction	1.0	0.4	1.0
Other differences, net	2.3	(2.0)	(1.7)
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)		2007	2006	2005
Current	– federal	$285	$394	$441
	– state	36	70	74
Deferred	– federal	13	(94)	(173)
	– state	11	(17)	(31)
State net operating loss carry forward		1	(2)	–
Investment tax credit		(12)	(12)	(13)
Total income tax expense		$334	$339	$298

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2007 or 2006.
- Taxes related to discontinued operations recorded net of tax for 2007, 2006 and 2005, which are presented separately in Notes 3A through 3H.
- Taxes related to other comprehensive income recorded net of tax for 2007, 2006 and 2005, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $2 million, which was recorded in common stock during 2005, related to excess tax deductions resulting from vesting of restricted stock awards and exercises of nonqualified stock options pursuant to the terms of our EIP.

In July 2006, the FASB issued FIN 48, which clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required for the application of FIN 48; recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority. We adopted the provisions of FIN 48 on January 1, 2007, which was accounted for as a $2 million reduction of the January 1, 2007, balance of retained earnings and a $4 million increase in regulatory assets. Including the cumulative effect impact, our liability for unrecognized tax benefits at January 1, 2007, was $126 million. Of the total amount of unrecognized tax benefits at January 1, 2007, $24 million would have affected the effective tax rate for income from continuing operations, if recognized. At December 31, 2007, our liability for unrecognized tax benefits decreased to $93 million and the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations decreased to $10 million. A reconciliation of the 2007 beginning and ending balances for unrecognized tax benefits is as follows:

(in millions)	
Unrecognized tax benefits at January 1, 2007	$126
Gross amounts of increases as a result of tax positions taken in a prior period	32
Gross amounts of decreases as a result of tax positions taken in a prior period	(41)
Gross amounts of increases as a result of tax positions taken in the current period	22
Gross amounts of decreases as a result of tax positions taken in the current period	(32)
Amounts of net decreases relating to settlements with taxing authorities	(14)
Reductions as a result of a lapse of the applicable statute of limitations	–
Unrecognized tax benefits at December 31, 2007	$93

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

Prior to the adoption of FIN 48, we accounted for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves under SFAS No. 5, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 1992 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2008.

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 2007, the interest expense related to unrecognized tax benefits was $1 million, net, of which a $15 million expense component was deferred as a regulatory asset by PEF and not recognized in our Consolidated Statement of Operations. During 2007 there were no penalties related to unrecognized tax benefits. As of January 1, 2007, we had accrued $24 million for interest and penalties. As of December 31, 2007, we have accrued $23 million for interest and penalties, which are included in 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 contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four Earthco 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. 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, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payment held in trust for 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2007.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

The components of the net periodic benefit cost for the years ended December 31 were:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2007**	2006	2005	**2007**	2006	2005
Service cost	**$46**	$45	$47	**$7**	$9	$9
Interest cost	**123**	117	117	**32**	33	33
Expected return on plan assets	**(155)**	(148)	(147)	**(6)**	(6)	(5)
Amortization of actuarial loss[a]	**15**	18	21	**2**	4	6
Other amortization, net[a]	**2**	–	–	**5**	5	5
Net periodic cost	**$31**	$32	$38	**$40**	$45	$48

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

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)," (SFAS No. 158) as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustments recognized as a component of OCI for the years ended December 31, 2006 and 2005 were net actuarial gains (losses) of $78 million and $(41) million, respectively. No amounts related to our OPEB plans were recognized as a component of OCI for the years ended December 31, 2006 and 2005. The table to the right provides a summary of amounts recognized in other comprehensive income for 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF.

(in millions)	Pension Benefits	Other Postretirement Benefits
Other comprehensive income (loss)		
Recognized for the year		
Net actuarial gain	$24	$16
Other, net	(1)	–
Reclassification adjustments		
Net actuarial loss	2	–
Other, net	1	–
Regulatory asset (increase) decrease		
Recognized for the year		
Net actuarial gain	66	82
Other, net	(8)	–
Amortized to income		
Net actuarial loss	13	2
Other, net	1	4

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. We used an expected long-term rate of 9.0%, the low end of the range, for 2007, 2006 and 2005.

The following weighted-average actuarial assumptions were used by Progress Energy in the calculation of its net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**5.95%**	5.65%	5.70%	**5.95%**	5.65%	5.70%
Rate of increase in future compensation						
Bargaining	**4.25%**	3.50%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.00%	**7.70%**	8.30%	8.25%

BENEFIT OBLIGATIONS AND ACCRUED COSTS

SFAS No 158 requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the benefit obligations and the funded status as of December 31, 2007 and 2006 are presented in the tables below, with each table followed by related supplementary information.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Projected benefit obligation at January 1	**$2,123**	$2,164	**$628**	$650
Service cost	**46**	45	**7**	9
Interest cost	**123**	117	**32**	33
Benefit payments	**(131)**	(174)	**(30)**	(29)
Plan amendment	**8**	18	**–**	(4)
Actuarial gain	**(27)**	(47)	**(96)**	(31)
Obligation at December 31	**2,142**	2,123	**541**	628
Fair value of plan assets at December 31	**1,996**	1,836	**75**	74
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $463 million and $2.123 billion at December 31, 2007 and 2006, respectively. Those plans had accumulated benefit obligations totaling $422 million and $2.083 billion at December 31, 2007 and 2006, respectively, and plan assets of $269 million and $1.836 billion at December 31, 2007 and 2006, respectively. The total accumulated benefit obligation for pension plans was $2.100 billion and $2.083 billion at December 31, 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Noncurrent assets	**$48**	$–	**$–**	$–
Current liabilities	**(10)**	(14)	**–**	(1)
Noncurrent liabilities	**(184)**	(273)	**(466)**	(553)
Funded status	**$(146)**	$(287)	**$(466)**	$(554)

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	**$22**	$49	**$(9)**	$7
Other, net	**6**	5	**1**	1
Recognized in regulatory assets, net				
Net actuarial loss	**136**	215	**25**	108
Other, net	**28**	22	**23**	28
Total not yet recognized as a component of net periodic cost[a]	**$192**	$291	**$40**	$144

[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 2008:

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$7	$1
Amortization of other, net[a]	2	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	
	2007	2006	**2007**	2006
Discount rate	**6.20%**	5.95%	**6.20%**	5.95%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**9.00%**	9.00%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2015**	2014

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

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash

Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

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

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$2
Effect on postretirement benefit obligation	31
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(2)
Effect on postretirement benefit obligation	(26)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our employer contributions for 2007 include contributions directly to pension plan assets of $63 million. 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 for Progress Energy. The OPEB benefits payments are also reduced by prescription drug-related federal subsidies received, which totaled $3 million and $2 million for 2007 and 2006, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2007**	2006	**2007**	2006
Fair value of plan assets at January 1	**$1,836**	$1,770	**$74**	$76
Actual return on plan assets	**219**	222	**7**	8
Benefit payments	**(131)**	(174)	**(30)**	(29)
Employer contributions	**72**	18	**24**	19
Fair value of plan assets at December 31	**$1,996**	$1,836	**$75**	$74

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	40%	**42%**	44%
Equity – international	15%	**25%**	23%
Debt – domestic	20%	**11%**	12%
Debt – international	10%	**12%**	9%
Other	15%	**10%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2008	**2007**	2006
Equity – domestic	25%	**28%**	30%
Equity – international	10%	**16%**	15%
Debt – domestic	50%	**41%**	40%
Debt – international	5%	**8%**	7%
Other	10%	**7%**	8%
Total	100%	**100%**	100%

The asset allocation for the benefit plans at the end of 2007 and 2006 and the target allocation for the plans, by asset category, are presented in the tables above.

For pension plan assets and a substantial portion of OPEB plan assets, we set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2008, we expect to make $34 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $149, $153, $155, $157, $164 and $877, respectively. The expected benefit payments for the OPEB plan for 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $37, $40, $43, $45, $47 and $247, 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 2008 through 2012 and in total for 2013 through 2017, in millions, are approximately $3, $3, $4, $4, $5 and $39, respectively.

B. Florida Progress Acquisition

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

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

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2007 and 2006, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million and $32 million, respectively.

A. Commodity Derivatives

GENERAL

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

In 2003, we recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2007 and 2006, the remaining liability was $10 million and $14 million, respectively.

DISCONTINUED OPERATIONS

As discussed in Note 3A, our subsidiary, PVI, entered into a series of transactions to sell or assign substantially all of its CCO physical and commercial assets and liabilities. On June 1, 2007, PVI closed the transaction involving the assignment of a contract portfolio consisting of 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. The sale of the generation assets closed on June 11, 2007. Additionally, we sold Gas on October 2, 2006 (See Note 3C). At December 31, 2007, with the exception of the oil price hedge instruments discussed below, our discontinued operations did not have outstanding positions in derivative instruments. For the year ended December 31, 2007, $88 million of after-tax gains from derivative instruments related to our nonregulated energy marketing and trading operations were included in discontinued operations on the Consolidated Statements of Income.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Notes 1C and 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 6A). As discussed in Note 3B, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

At December 31, 2006, derivative assets of $107 million and derivative liabilities of $31 million were included in assets to be divested and liabilities to be divested, respectively, on the Consolidated Balance Sheet. Due to the divestitures discussed above, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled, and cash flow hedge accounting for the contracts was discontinued beginning in the second quarter of 2006 for Gas and in the fourth quarter of 2006 for CCO. Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. For the years ended December 31, 2006 and 2005, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ended December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ended December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges.

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. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Consolidated Balance Sheets, respectively, until the contracts are settled (See Note 7A). Once settled, any realized gains or losses are passed through the fuel clause. During the year ended December 31, 2007, PEC recorded a net realized loss of $9 million. PEC's net realized gains and losses were not material during the years ended December 31, 2006 and 2005. During the years ended December 31, 2007, 2006 and 2005, PEF recorded a net realized loss of $46 million, a net realized gain of $39 million and a net realized gain of $70 million, respectively.

Excluding amounts receiving regulatory accounting treatment and amounts related to our discontinued operations discussed above, gains and losses from contracts entered into for economic hedging purposes were not material to our results of operations during the years ended December 31, 2007, 2006 and 2005. Excluding derivative assets and derivative liabilities to be divested discussed above, we did not have material outstanding positions in such contracts at December 31, 2007 and 2006, other than those receiving regulatory accounting treatment at PEC and PEF, as discussed below.

At December 31, 2007, the fair value of PEC's commodity derivative instruments was recorded as a $19 million long-term derivative asset position included in other assets and deferred debits and a $3 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, PEC did not have material outstanding positions in such contracts.

At December 31, 2007, the fair value of PEF's commodity derivative instruments was recorded as a $60 million short-term derivative asset position included in prepayments and other current assets, a $90 million long-term derivative asset position included in derivative assets, and a $15 million short-term derivative liability position included in other current liabilities on the Consolidated Balance Sheet. At December 31, 2006, the fair value of such instruments was recorded as a $2 million long-term derivative asset position included in derivative assets, an $87 million short-term derivative liability position included in other current liabilities, and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Consolidated Balance Sheet.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of power for our forecasted sales. Realized gains and losses are recorded net in operating revenues. At December 31, 2007 and 2006, 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 2007, 2006 and 2005.

At December 31, 2007 and 2006, 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. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

The fair values of open interest rate cash flow hedges at December 31 were as follows:

(in millions)	2007	2006
Fair value of liabilities	$(12)	$(2)

Gains and losses from cash flow hedges are recorded in accumulated other comprehensive income and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our results of operations for 2007, 2006 and 2005.

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2007:

(term in years/millions of dollars)	
Maximum term	Less than 1
Accumulated other comprehensive loss, net of tax[a]	$(24)
Portion expected to be reclassified to earnings during the next 12 months[b]	$(2)

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

At December 31, 2006, including amounts related to terminated hedges, we had $14 million of after-tax deferred losses, including $5 million of after-tax deferred losses at PEC and $1 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

At December 31, 2007 and 2006, PEC had $200 million notional and $50 million notional, respectively, of interest rate cash flow hedges. During 2007, PEC entered into a combined $150 million notional of forward starting swaps and amended its $50 million notional 10-year forward starting swap in order to move the maturity date from October 1, 2017 to April 1, 2018, which now requires mandatory cash settlement on April 1, 2008.

In 2007, PEF entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. At December 31, 2006, PEF had $50 million notional of interest rate cash flow hedges. All of PEF's forward starting swaps were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. On January 8, 2008, PEF entered into a combined $200 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, 2007, we had no open interest rate fair value hedges. At December 31, 2006, we had $50 million notional of interest rate fair value hedges.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2007, the Parent had issued $433 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

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

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2007, 2006 and 2005 to PEC amounted to $182 million, $188 million and $202 million, respectively, and services provided to PEF were $174 million, $165 million and $169 million, respectively.

Progress Fuels sold coal to PEF at cost in 2007 and 2006 and for an insignificant profit in 2005. These intercompany revenues and expenses are eliminated in consolidation, however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $2 million, $321 million and $402 million for the years ended December 31, 2007, 2006 and 2005, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Our former Coal and Synthetic Fuels segment was previously involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties and coal terminal services. In 2007, we reclassified the operations of our synthetic fuels businesses and coal terminal services as discontinued operations (See Note 3B). For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005. Postretirement and severance charges reclassified to discontinued operations are not included in the table below

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the former Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the former Coal and

Synthetic Fuels segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable The profits realized for 2007, 2006 and 2005 were not significant Prior to 2006, income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA 1935, the Parent stopped allocating these tax benefits in 2006

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 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 and amortization	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,962	10,004	16,383	(12,115)	26,234
Capital and investment expenditures	941	1,262	3	(2)	2,204
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$4,086	$4,638	$–	$–	$8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation and amortization	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	12,020	8,593	15,421	(11,293)	24,741
Capital and investment expenditures	808	741	12	(9)	1,552
As of and for the year ended December 31, 2005					
Revenues					
Unaffiliated	$3,991	$3,955	$2	$–	$7,948
Intersegment	–	–	839	(839)	–
Total revenues	3,991	3,955	841	(839)	7,948
Depreciation and amortization	561	334	31	–	926
Interest income	8	1	94	(90)	13
Total interest charges, net	192	126	342	(85)	575
Postretirement and severance charges	55	102	1	–	158
Income tax expense (benefit)	239	121	(62)	–	298
Segment profit (loss)	490	258	(225)	–	523
Total assets	11,502	8,318	18,278	(13,673)	24,425
Capital and investment expenditures	682	543	19	(19)	1,225

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the accompanying Consolidated Statements of Income for the years ended December 31 were as follows:

(in millions)	**2007**	2006	2005
Other income			
Nonregulated energy and delivery services income	**$36**	$41	$32
DIG Issue C20 amortization (Note 17A)	**4**	5	7
Contingent value obligation unrealized gain (Note 15)	**2**	–	6
Gain on sale of Level 3 stock[a]	–	32	–
Investment gains	**9**	4	4
Income from equity investments	**2**	1	1
AFUDC equity	**51**	21	16
Reversal of indemnification liability (Note 21B)	–	29	–
Other	**15**	13	16
Total other income	**119**	146	82
Other expense			
Nonregulated energy and delivery services expenses	**24**	27	23
Donations	**22**	20	18
Contingent value obligation unrealized loss (Note 15)	**4**	25	–
Investment losses	**4**	–	1
Loss from equity investments	**5**	3	7
Loss on debt redemption[b]	–	59	–
FERC audit settlement	–	–	7
Indemnification liability (Note 21B)	–	13	16
Other	**16**	15	11
Total other expense	**75**	162	83
Other, net	**$44**	$(16)	$(1)

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3E). These gains are prior to the consideration of minority interest.

(b) On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the United States Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various 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 these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

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

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	2007	2006
PEC		
MGP and other sites[a]	**$16**	$22
PEF		
Remediation of distribution and substation transformers	**31**	43
MGP and other sites	**17**	18
Total PEF environmental remediation accruals[b]	**48**	61
Progress Energy nonregulated operations	–	3
Total Progress Energy environmental remediation accruals	**$64**	$86

[a] Expected to be paid out over one to five years.
[b] Expected to be paid out over one to fifteen years.

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, our environmental sites include the following related to our nonregulated operations.

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. At December 31, 2006, the remaining accrual balance was approximately $3 million. For the year ended December 31, 2007, the accrual was reduced by approximately $3 million due to a reduction in the anticipated scope of work based on responses from regulatory agencies. Expenditures related to this liability were not material during 2007 and 2006.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2007, including the Carolina Transformer site, the Ward Transformer site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses, net of insurance proceeds (See Note 7B).

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. The maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced PEC's allocable share, and the estimated scope of work increased. These factors resulted in a net reduction to PEC's accrual for this site. At December 31, 2007, PEC's recorded liability for the site was approximately $6 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

The EPA has also proposed, but not yet selected, a final remedial action plan to address stream segments downstream from the Ward Transformer site. The outcome of this matter cannot be predicted.

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $33 million. During the year ended December 31, 2007, a settlement was reached between the PRPs and the EPA, and PEC recorded and paid an immaterial amount for its share of the settlement.

PEF

PEF has received approval from the FPSC for recovery of the majority of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our results of operations or financial condition.

B. Air and Water Quality

We are subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations include the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call), the Clean Smokestacks Act and mercury regulation (see "Other Matters – Environmental Matters" for discussion regarding Clean Air Mercury Rule (CAMR)). At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.567 billion, including $1.244 billion at PEC and $323 million at PEF. At December 31, 2006, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $932 million, including $904 million at PEC and $28 million at PEF.

As discussed in Note 7A, 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, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2007, and 2006, the amount of the liability was $30 million and $29 million, respectively, based upon the respective current estimates for Clean Smokestacks Act compliance. 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. In 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and accordingly, recorded the indemnification expense to Clean Smokestacks Act amortization. In a settlement agreement provisionally approved by the NCUC on December 20, 2007, eligible compliance costs in excess of the joint owner's share will be treated in the same manner as PEC's Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs, as ultimately approved by the NCUC (See Note 7A).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2007, the table below reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due.

(in millions)	2008	2009	2010	2011	2012	Thereafter
Fuel	$2,018	$1,745	$1,202	$1,001	$675	$5,103
Purchased power	455	422	409	443	415	3,756
Construction obligations	714	211	42	–	–	–
Other purchase obligations	94	39	32	16	16	64
Total	$3,281	$2,417	$1,685	$1,460	$1,106	$8,923

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $2.360 billion, $1.628 billion and $1.470 billion for 2007, 2006 and 2005, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2008 to 2030. These purchased power contracts generally provide for capacity and energy payments.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $77 million, $80 million and $71 million for 2007, 2006 and 2005, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $39 million, $40 million and $44 million in 2007, 2006 and 2005, respectively.

In 2007, PEC executed a long-term agreement for the purchase of power from Southern Power Company. The agreement provides for capacity purchases of 305 MW for 2010, 310 MW for 2011 and 150 MW annually thereafter through 2019. Estimated payments for capacity and energy under the agreement are $22 million for 2010, $33 million for 2011 and $14 million annually thereafter through 2019. PEC has various pay-for-performance contracts with QFs for approximately 195 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $95 million, $182 million and $112 million in 2007, 2006 and 2005, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $161 million, $162 million and $175 million for 2007, 2006 and 2005, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $70 million annually through 2011, $50 million for 2012 and $32 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 965 MW of capacity with expiration dates ranging from 2008 to 2030. Energy payments are based on the actual power taken under these contracts Capacity payments are subject to the QFs meeting certain contract performance obligations In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments, except one for 75 MW, have been approved by the FPSC. Total capacity purchases under these contracts amounted to $288 million, $277 million and $262 million for 2007, 2006 and 2005, respectively At December 31, 2007, minimum expected future capacity payments under these contracts were $297 million, $263 million, $267 million, $281 million and $292 million for 2008 through 2012, respectively, and $3.053 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In January 2006, PEF entered into a conditional contract with Gulfstream Natural Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008, through January 1, 2031 The total cost to PEF associated with this agreement is approximately $777 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2006, PEF entered into a conditional contract with Devon Gas Services for the supply of natural gas to augment PEF's gas supply needs for the period from May to September for the years 2008 through 2011 The total cost to PEF associated with this agreement is approximately $251 million The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $1 026 billion The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million The transaction is subject to several conditions precedent, including FPSC approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through March 31, 2013. The total cost to PEF associated with this agreement is approximately $146 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In January and February 2007, PEF entered into conditional contracts with Chevron Natural Gas for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, to May 31, 2013. The total cost to PEF associated with these agreements is approximately $935 million. The transactions are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate pipeline expansions, and other standard closing conditions Due to the conditions of these agreements the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $675 million, $365 million and $91 million for 2007, 2006 and 2005, respectively Our future obligations related to Clean Smokestacks Act capital projects are $84 million for 2008 and $22 million for 2009. We have purchase obligations related to various capital projects related to new generation and Florida CAIR Our future obligations under these contracts are $631 million, $188 million and $42 million for 2008 through 2010, respectively

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $122 million and $100 million for 2007, 2006 and 2005, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $8 million, $18 million and $17 million for 2007, 2006 and 2005, respectively. Estimated future payments under these contracts of $6 million are not reflected in the contractual cash obligations table above. Included in these contracts are purchase obligations with a counterparty for pipeline capacity through 2009.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $21 million, $2 million and $10 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $22 million for 2008, $4 million each for 2009 and 2010, and $3 million each for 2011 and 2012 and $13 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006 and $13 million for 2005, with no purchases in 2007. Future obligations under these contracts are for spent fuel storage and total $5 million, $8 million, $3 million and $1 million for 2008 through 2011, respectively.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $11 million, $12 million and $8 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $21 million, $14 million, $19 million, $12 million and $12 million for 2008 through 2012, respectively, with approximately $50 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $22 million, $21 million and $34 million for 2007, 2006 and 2005, respectively. Future obligations under these contracts are $8 million and $6 million for 2008 and 2009, respectively.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $40 million, $42 million and $38 million for 2007, 2006 and 2005, respectively. Our purchased power expense under agreements classified as operating leases was approximately $69 million, $60 million and $14 million in 2007, 2006 and 2005, respectively.

Assets recorded under capital leases at December 31 consisted of:

(in millions)	**2007**	2006
Buildings	**$267**	$84
Less: Accumulated amortization	**(20)**	(12)
Total	**$247**	$72

At December 31, 2007, 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
2008	$28	$62
2009	29	41
2010	28	25
2011	28	20
2012	28	38
Thereafter	308	554
Minimum annual payments	449	$740
Less amount representing imputed interest	(202)	
Present value of net minimum lease payments under capital leases	$247	

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 2007, PEF entered into a purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from 2012 through 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 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 an agreement for purchased power, which is classified as a capital lease, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from 2007 through 2024 for a total of approximately $348 million. Due to the conditions of the agreement, the capital lease was not recorded on our Consolidated Balance Sheets until 2007.

In 2006, PEF entered into an agreement for purchased power, which is classified as a capital lease. Due to the conditions of the agreement, the capital lease will not be recorded on the Consolidated Balance Sheets until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $8 million from 2012 through 2036 for a total of approximately $208 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $8 million, $7 million, $5 million, $4 million and $2 million for 2008 through 2012, respectively. Rents received under these operating leases totaled $8 million, $9 million and $8 million for 2007, 2006 and 2005, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2008 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million for 2007 and $31 million each for 2006 and 2005. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $78 million, $72 million and $63 million for 2007, 2006 and 2005, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2008 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2007, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Balance Sheets.

At December 31, 2007, 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, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations, which are within the scope of FIN 45. Related to the sales of businesses, the latest notice period extends until 2012 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2007, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $427 million. At December 31, 2007 and 2006, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $80 million and $60 million, respectively. 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. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level radioactive waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been presented in the trials or appeals during 2006 and 2007 Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006. The trial court lifted the stay on March 22, 2006, and discovery commenced. The trial court issued a scheduling order on March 23, 2006, and the case went to trial beginning November 5, 2007 Closing arguments are anticipated in the second quarter of 2008 with a ruling expected later in 2008 The Utilities cannot predict the outcome of this matter 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.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev In January 2003, the state of Nevada, Clark County, Nev.; and the city of Las Vegas petitioned the U S Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and subsequently reported that the license application would be submitted by June 2008 if full funding was obtained for the project. The DOE requested $545 million for fiscal year 2007 and received $445 million. The DOE requested $495 million for fiscal year 2008. However, Congress passed an appropriations bill which allocates $390 million in fiscal year 2008 for DOE's Yucca Mountain repository program. As a result of the fiscal year budget reductions, the schedule for submitting the license application is being re-evaluated by the DOE. The impact to the Yucca Mountain repository program cannot be predicted at this time.

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

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

SYNTHETIC FUELS MATTERS

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC, Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities and (3) a number of tort claims related to the contracts.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.* (the Florida Global Case), asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003, and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. The parties are currently engaged in discovery in the Florida Global Case.

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

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The suit continues now under contract theories alone. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures in accordance with SFAS No. 5 to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes

Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The yearly interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2007, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of Terminals and the synthetic fuels businesses as discontinued operations as described in Note 3B.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,768	$4,385	$9,153
Affiliate revenues	–	89	(89)	–
Total operating revenues	–	4,857	4,296	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	998	1,842
Depreciation and amortization	–	369	536	905
Taxes other than on income	–	309	192	501
Other	–	20	10	30
Total operating expenses	10	4,178	3,419	7,607
Operating (loss) income	(10)	679	877	1,546
Other income, net	27	47	4	78
Interest charges, net	203	198	187	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	528	694	1,036
Income tax (benefit) expense	(79)	117	296	334
Equity in earnings of consolidated subsidiaries	596	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	489	402	(198)	693
Discontinued operations, net of tax	15	(59)	(145)	(189)
Net income (loss)	$504	$343	$(343)	$504

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$4,637	$4,087	$8,724
Affiliate revenues	–	41	(41)	–
Total operating revenues	–	4,678	4,046	8,724
Operating expenses				
Fuel used in electric generation	–	1,835	1,173	3,008
Purchased power	–	766	334	1,100
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	406	605	1,011
Taxes other than on income	–	309	191	500
Other	–	21	14	35
Total operating expenses	14	4,021	3,202	7,237
Operating (loss) income	(14)	657	844	1,487
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	182	166	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	530	699	906
Income tax (benefit) expense	(123)	174	288	339
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	(16)
Income (loss) from continuing operations	579	340	(368)	551
Discontinued operations, net of tax	(3)	359	(331)	20
Net income (loss)	$571	$699	$(699)	$571

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Non-affiliate revenues	$–	$3,956	$3,992	$7,948
Affiliate revenues	–	188	(188)	–
Total operating revenues	–	4,144	3,804	7,948
Operating expenses				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	337	589	926
Taxes other than on income	4	279	177	460
Other	–	(5)	2	(3)
Total operating expenses	16	3,480	3,064	6,560
Operating (loss) income	(16)	664	740	1,388
Other income (expense), net	66	(1)	(53)	12
Interest charges, net	305	163	107	575
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(255)	500	580	825
Income tax (benefit) expense	(64)	96	266	298
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' income, net of tax	–	(4)	–	(4)
Income (loss) from continuing operations	693	400	(570)	523
Discontinued operations, net of tax	4	(26)	195	173
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$7,600	$9,005	$16,605
Current assets				
Cash and cash equivalents	185	43	27	255
Short-term investments	–	–	1	1
Notes receivable from affiliated companies	157	149	(306)	–
Deferred fuel cost	–	6	148	154
Assets to be divested	–	48	4	52
Prepayments and other current assets	21	1,211	1,081	2,313
Total current assets	363	1,457	955	2,775
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,969	–	(10,969)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	149	1,551	1,551	3,251
Total deferred debits and other assets	11,118	1,552	(5,764)	6,906
Total assets	$11,481	$10,609	$4,196	$26,286
Capitalization				
Common stock equity	$8,422	$3,052	$(3,052)	$8,422
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	81	3	84
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,597	2,686	3,183	8,466
Total capitalization	11,019	6,162	155	17,336
Current liabilities				
Current portion of long-term debt	–	577	300	877
Short-term debt	201	–	–	201
Notes payable to affiliated companies	–	227	(227)	–
Regulatory liabilities	–	173	–	173
Liabilities to be divested	–	8	–	8
Other current liabilities	215	1,028	746	1,989
Total current liabilities	416	2,013	819	3,248
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	59	302	361
Regulatory liabilities	–	1,316	1,223	2,539
Accrued pension and other benefits	12	347	404	763
Capital lease obligations	–	224	15	239
Other liabilities and deferred credits	34	488	1,278	1,800
Total deferred credits and other liabilities	46	2,434	3,222	5,702
Total capitalization and liabilities	$11,481	$10,609	$4,196	$26,286

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$6,337	$8,908	$15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets to be divested	–	121	845	966
Prepayments and other current assets	27	1,060	1,029	2,116
Total current assets	259	1,258	2,097	3,614
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,556	1,511	3,193
Total deferred debits and other assets	10,866	1,557	(5,575)	6,848
Total assets	$11,125	$9,152	$5,430	$25,707
Capitalization				
Common stock equity	$8,286	$2,708	$(2,708)	$8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities to be divested	–	72	176	248
Other current liabilities	210	1,224	814	2,248
Total current liabilities	210	1,497	1,113	2,820
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	251	312
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	557	1,261	1,851
Total deferred credits and other liabilities	47	2,086	3,530	5,663
Total capitalization and liabilities	$11,125	$9,152	$5,430	$25,707

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$76	$489	$687	$1,252
Investing activities				
Gross property additions	–	(1,218)	(755)	(1,973)
Nuclear fuel additions	–	(44)	(184)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	624	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	(1,413)
~~Proceeds from sales of available-for-sale securities and other investments~~	~~21~~	~~640~~	~~791~~	~~1,452~~
Changes in advances to affiliates	(99)	(112)	211	–
Return of investment in consolidated subsidiary	340	–	(340)	–
Other investing activities	(31)	32	29	30
Net cash provided (used) by investing activities	231	(1,291)	(397)	(1,457)
Financing activities				
Issuance of common stock	151	–	–	151
Dividends paid on common stock	(627)	–	–	(627)
Dividends paid to parent	–	(10)	10	–
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)
Changes in advances from affiliates	–	151	(151)	–
Other financing activities	–	49	6	55
Net cash (used) provided by financing activities	(275)	805	(335)	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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2006 *(in millions)*	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,110	$(404)	$2,001
Investing activities				
Gross property additions	–	(865)	(707)	(1,572)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	415	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	419	(1,035)	127
Financing activities				
Issuance of common stock	185	–	–	185
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Net decrease in short-term debt	–	(102)	(73)	(175)
Proceeds from issuance of long-term debt, net	397	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Changes in advances from affiliates	–	(243)	243	–
Other financing activities	(8)	(8)	(52)	(68)
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$153	$40	$72	$265

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$509	$701	$1,467
Investing activities				
Gross property additions	–	(714)	(599)	(1,313)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	(2)	(40)
Net cash provided (used) by investing activities	690	(320)	(1,514)	(1,144)
Financing activities				
Issuance of common stock	208	–	–	208
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Net decrease in short-term debt	(170)	(191)	(148)	(509)
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	50	(9)	32
Net cash (used) provided by financing activities	(713)	27	913	227
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$239	$239	$127	$605

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. The 2007 and 2006 amounts were restated for discontinued operations (See Note 3).

(in millions except per share data)	First[a]	Second[a]	Third[a]	Fourth[a]
2007				
Operating revenues	**$2,072**	**$2,129**	**$2,750**	**$2,202**
Operating income	**351**	**301**	**610**	**284**
Income from continuing operations	**159**	**106**	**327**	**101**
Net income (loss)	**275**	**(193)**	**319**	**103**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.63**	**0.42**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Diluted earnings per common share				
Income from continuing operations	**0.62**	**0.41**	**1.27**	**0.39**
Net income (loss)	**1.08**	**(0.75)**	**1.24**	**0.40**
Dividends declared per common share	**0.610**	**0.610**	**0.610**	**0.615**
Market price per share – High	**51.60**	**52.75**	**49.48**	**50.25**
– Low	**47.05**	**45.15**	**43.12**	**44.75**
2006				
Operating revenues	$1,985	$2,083	$2,599	$2,057
Operating income	295	332	570	290
Income from continuing operations	67	110	268	106
Net income (loss)	45	(47)	319	254
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.27	0.44	1.07	0.42
Net income (loss)	0.18	(0.19)	1.27	1.01
Dividends declared per common share	0.605	0.605	0.605	0.610
Market price per share – High	45.31	45.16	46.22	49.55
– Low	42.54	40.27	42.05	44.40

[a] Operating results have been restated for discontinued operations

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 *(in millions, except per share data)*	2007	2006[a]	2005[a]	2004[a]	2003[a]
Operating results					
Operating revenues	**$9,153**	$8,724	$7,948	$7,168	$6,775
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**693**	551	523	552	536
Net income	**504**	571	697	759	782
Per share data					
Basic earnings					
Income from continuing operations	**$2.71**	$2.20	$2.12	$2.28	$2.26
Net income	**1.97**	2.28	2.82	3.13	3.30
Diluted earnings					
Income from continuing operations	**2.70**	2.20	2.12	2.27	2.25
Net income	**1.96**	2.28	2.82	3.12	3.28
Assets	**$26,286**	$25,707	$27,066	$26,013	$26,198
Capitalization and Debt					
Common stock equity	**$8,422**	$8,286	$8,038	$7,633	$7,444
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**84**	10	36	29	24
Long-term debt, net[b]	**8,737**	8,835	10,446	9,521	9,693
Current portion of long-term debt	**877**	324	513	349	868
Short-term debt	**201**	–	175	684	4
Capital lease obligations	**247**	72	18	19	20
Total capitalization and debt	**$18,661**	$17,620	$19,319	$18,328	$18,146
Other financial data					
Return on average common stock equity (percent)	**5.97%**	7.05%	8.91%	9.99%	11.07%
Ratio of earnings to fixed charges	**2.62**	2.08	2.11	2.23	2.06
Number of common shareholders of record	**58,991**	64,899	67,638	70,159	72,792
Book value per common share	**$32.66**	$32.71	$32.35	$31.39	$30.94
Dividends declared per common share	**$2.45**	$2.43	$2.38	$2.32	$2.26
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**51,163**	48,770	52,306	50,782	51,501
Nuclear	**30,336**	30,602	30,120	30,445	30,576
Combusion turbines/combined cycle	**13,319**	11,857	11,349	9,695	7,819
Hydro	**415**	594	749	802	955
Purchased	**14,994**	14,664	14,566	13,466	13,848
Total energy supply (Company share)	**110,227**	106,487	109,090	105,190	104,699
Joint-owner share[c]	**5,351**	5,224	5,388	5,395	5,213
Total system energy supply	**115,578**	111,711	114,478	110,585	109,912

[a] *Operating results and balance sheet data have been restated for discontinued operations.*
[b] Includes long-term debt to affiliated trust of $271 million at December 31, 2007 and 2006, and $270 million at December 31, 2005, 2004 and 2003 (See Note 23)
[c] Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned

We use ongoing earnings per share to evaluate the operations and to establish goals for management and employees. We believe this presentation is appropriate and enables investors to more accurately compare our ongoing financial performance over the periods presented. Ongoing earnings as presented here may not be comparable to similarly titled measures used by other companies. Reconciling adjustments from ongoing earnings per share to GAAP are as follows.

December 31	2007	2006	2005
Core ongoing earnings per share[a]	**$2.81**	$2.63	$2.70
Noncore ongoing earnings per share[b]	**(0.09)**	(0.19)	(0.19)
Total ongoing earnings per share	**2.72**	2.44	2.51
Contingent value obligations mark-to-market	**(0.01)**	(0.10)	0.03
Discontinued operations	**(0.74)**	0.08	0.70
Loss on debt redemptions	–	(0.14)	–
Postretirement and severance charges	–	–	(0.42)
Reported GAAP earnings per share	**$1.97**	$2.28	$2.82

[a] Core ongoing earnings primarily includes the utility operations, corporate eliminations and the holding company

[b] Noncore ongoing earnings primarily includes the allocation of corporate overhead costs associated with divested business

Contingent Value Obligation (CVO) Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, we issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuel facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are debt instruments and, under GAAP, are valued at fair value. Unrealized gains and losses from changes in market value are recognized in earnings. Since changes in the fair value of the CVOs do not affect our underlying obligation, we do not consider the adjustment a component of ongoing earnings.

Discontinued Operations

The operations of businesses that have been sold or are in the process of being sold are reported as discontinued operations, and therefore we do not view these activities as representative of our ongoing operations. Our discontinued operations include CCO, Rowan and DeSoto, Winchester Energy; Progress Telecom, LLC; Dixie Fuels; Progress Materials, Inc.; Coal Mining; Progress Rail; MEMCO; Synthetic Fuels business; and Coal Terminal services.

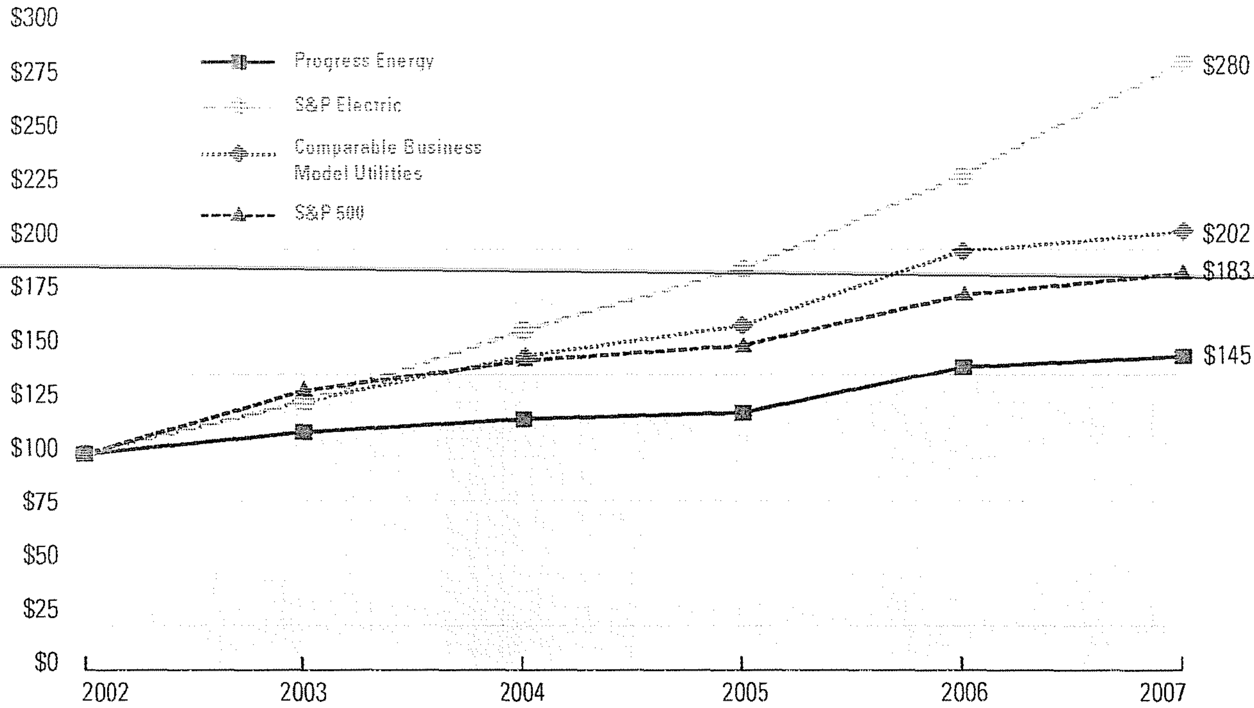
Loss on Redemptions of Debt

In November 2006, the Parent redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. In December 2006, the Parent repurchased, pursuant to a tender offer, $550 million, or approximately 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. Due to the nonrecurring nature of this loss, we do not believe it is representative of our ongoing operations.

Postretirement and Severance Charges

As part of our cost-management initiative, we approved a workforce restructuring in February 2005, which resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program, in which 1,450 eligible employees elected to participate. In connection with this initiative, we incurred charges related to estimated future payments for severance benefits that will be paid out over time. Due to the nonrecurring nature of the charge, we do not believe it is representative of our ongoing operations.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN[a] AMONG PROGRESS ENERGY, INC., S&P 500 STOCK INDEX, S&P ELECTRIC INDEX AND COMPARABLE BUSINESS MODEL UTILITIES



Measurement Period (Fiscal Year Covered)	2002	2003	2004	2005	2006	2007
Progress Energy, Inc.	$100	$110	$116	$119	$140	$145
S&P 500 Index	100	129	143	150	173	183
Comparable Business Model Utilities	100	124	145	159	193	202
S&P Electric Index	100	124	157	185	228	280

[a] $100 invested on 12/31/2002 in Stock or Index. Including reinvestment of dividends. Fiscal year ending 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 have a market capitalization structure greater than $3.5 billion and are generally categorized in our subsector are Southern Company, Duke Energy, SCANA, Xcel, PG&E, Wisconsin Energy and Pinnacle West.

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 the industry evolution discussed above. 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 2008 annual meeting of shareholders will be held May 14, 2008, at 10 a m in the Fletcher Opera Theater at the Progress Energy Center for the Performing Arts in Raleigh, N C. A formal notice of the meeting with a proxy statement will be mailed to shareholders in early April.

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

We also offer online access to shareholder accounts via the Internet. To obtain online access to your shareholder account, go to computershare com/investor to register.

If you have access to Progress Energy's annual report at your address, and do not want to receive a copy for your shareholder account, please call our transfer agent, Computershare, toll-free at **1.866.290.4388** to discontinue receiving annual reports by mail.

Dividend-reinvestment statements, tax documents and proxy material, including the annual report, can be electronically delivered to shareholders. Electronic delivery provides immediate access to proxy material and allows Internet voting while saving printing and mailing costs. To take advantage of electronic delivery of documents, go to **computershare.com/investor**, log in to your account, select Electronic Shareholder Communications and follow the instructions.

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

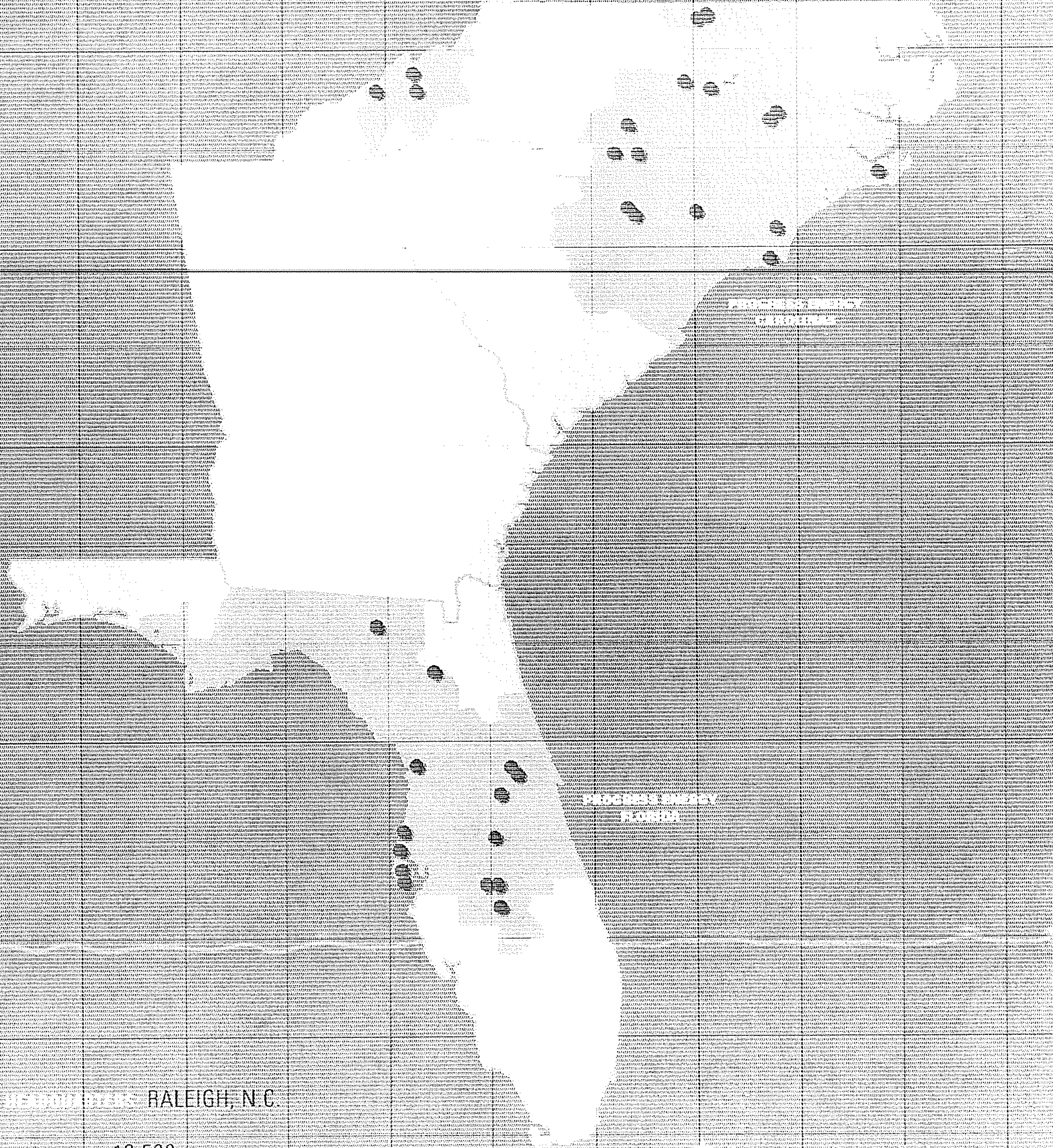
Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders upon written request to the company's treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information. 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.

NYSE Certifications

Because Progress Energy's common stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 1, 2007. In addition, we have filed, as exhibits to the Annual Report on Form 10-K for the year ended December 31, 2007, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the Securities and Exchange Commission regarding the quality of our public disclosure.

PROGRESS ENERGY AT A GLANCE



RALEIGH, N.C.

10,500

3.1 MILLION

54,000 SQUARE MILES

Environmental stewardship is Progress Energy's commitment, and my responsibility every day

– Dave Bruzek, lead environmental specialist for natural resources, Progress Energy Florida

Progress Energy

Progress Energy, Inc.
P.O. Box 1551
Raleigh, N.C. 27602-1551
progress-energy.com

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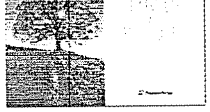

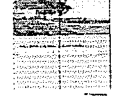

See Progress Energy's Corporate Responsibility
and Global Climate Change reports
at progress-energy.com/environment

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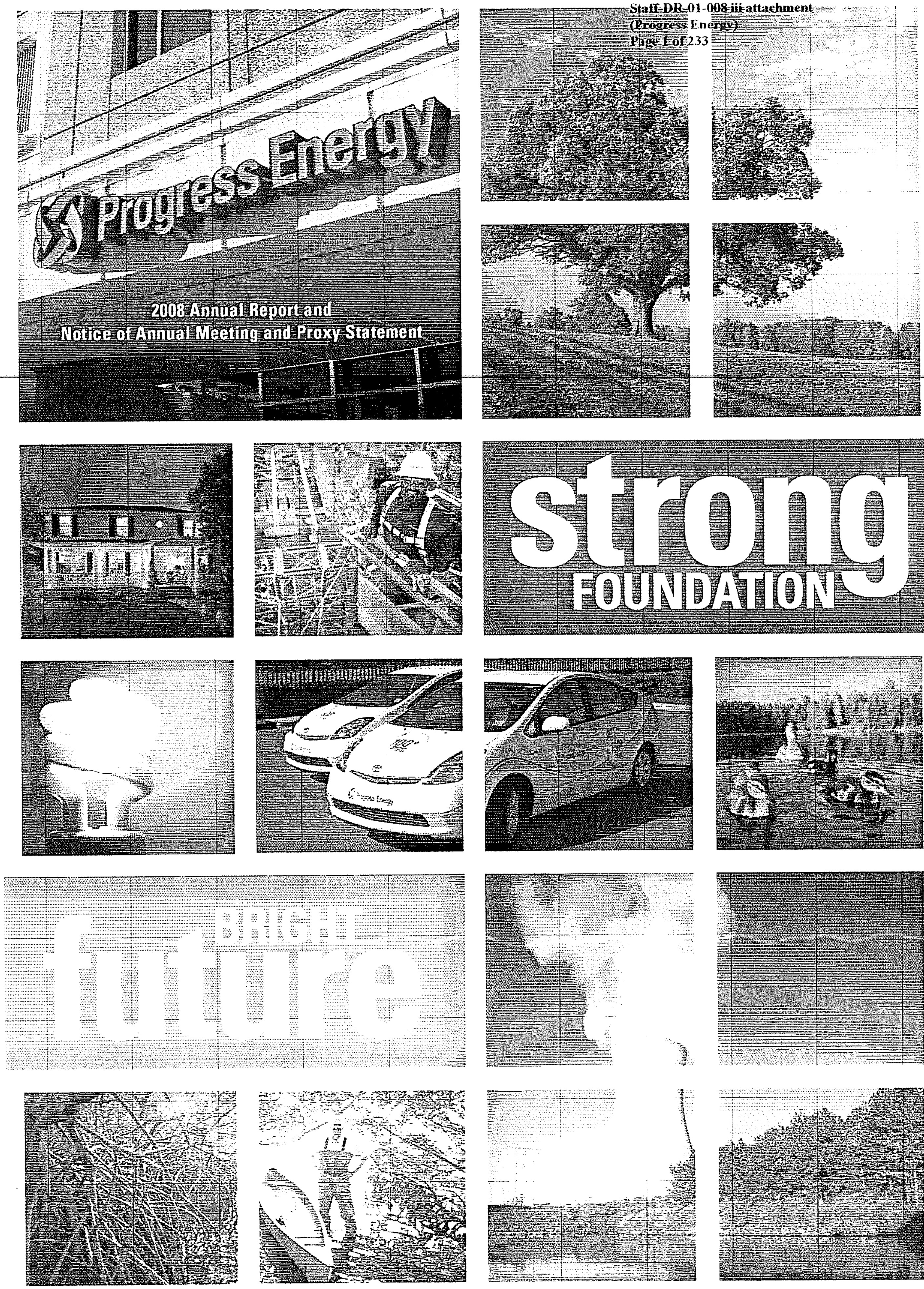
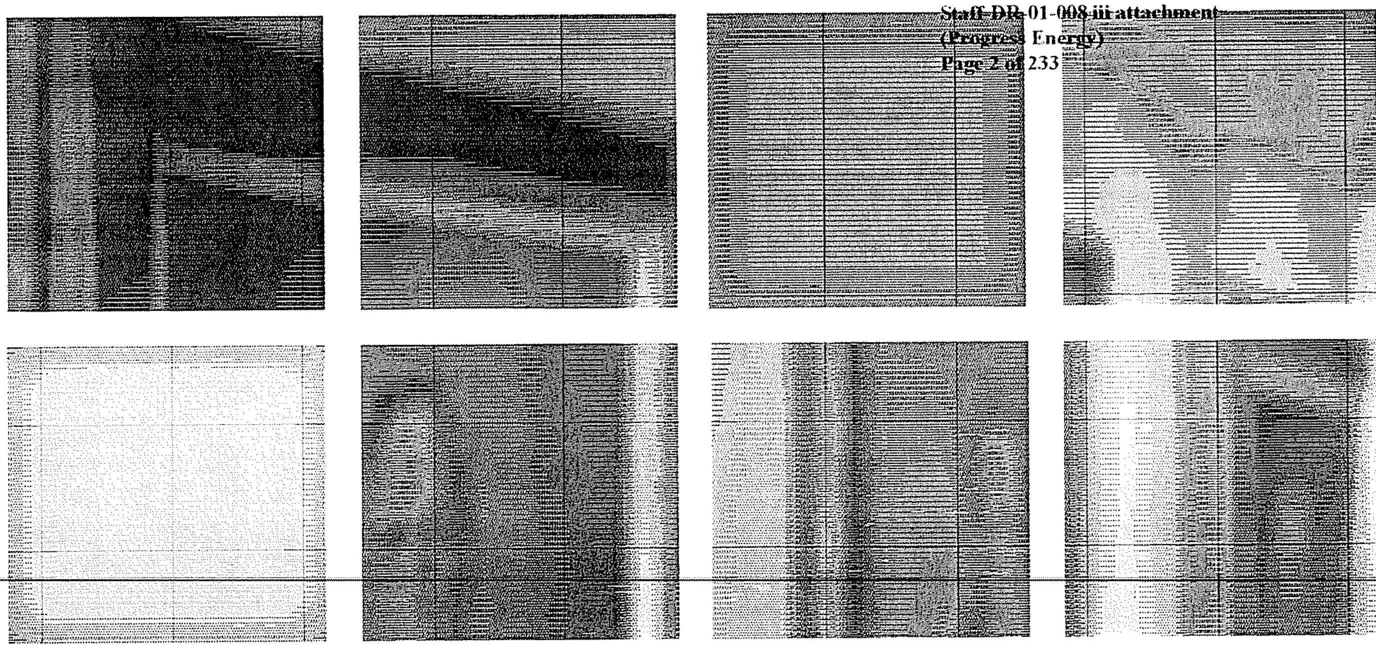
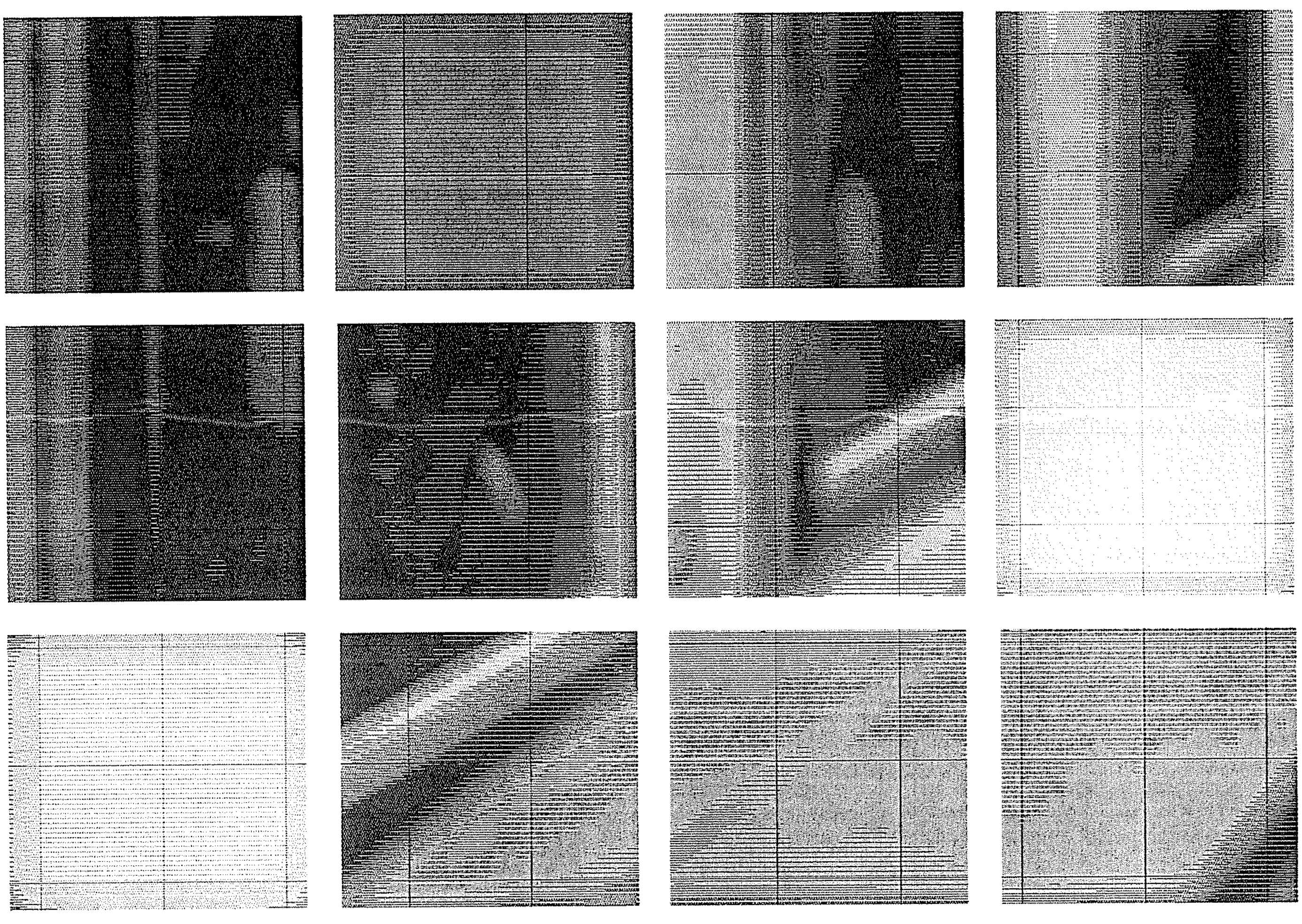
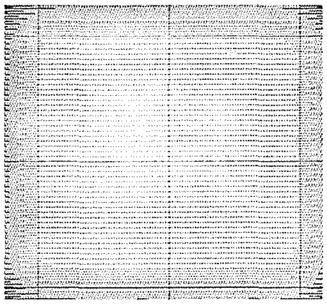
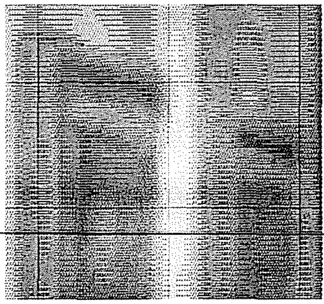
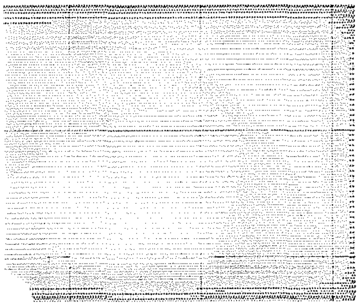

Progress Energy
2008 Annual Report and
Notice of Annual Meeting and Proxy Statement
strong
FOUNDATION
BRIGHT
future



message from our CEO

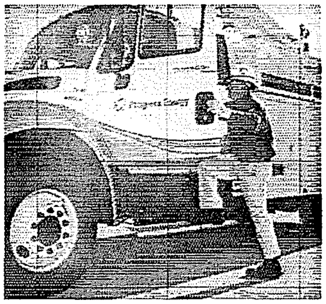
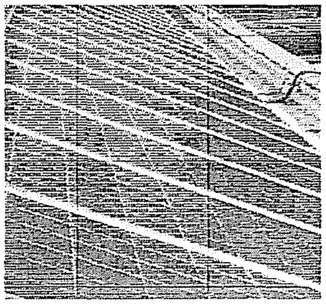
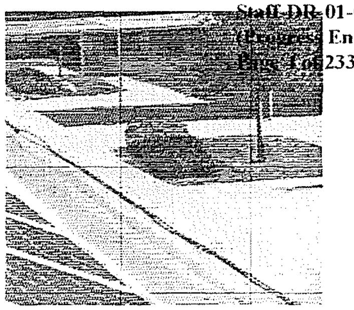
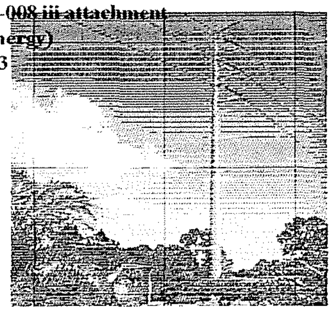


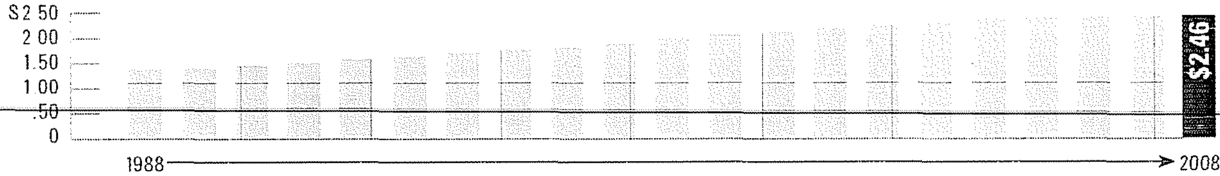

DEAR SHAREHOLDERS: The economic landscape is so fluid these days that it might already seem like old news now to report on the year gone by. So my intent with this letter is to go beyond a simple recap of 2008. I want to give you a clear sense of how Progress Energy is managing the business through this extraordinary period in our national economy and financial markets, and how we're investing in the future for our customers and investors.

The overall financial and operational results we are achieving indicate our resilience and resolve and the strength of having a clear strategy focused on an essential service we know and perform well. Early last year, we completed the multiyear transition back to our core regulated electric utility business: Progress Energy Carolinas and Progress Energy Florida. These two strong electric utilities have our complete focus.

We know that millions of people depend on us every day. That's why we're staying focused on the fundamentals of our business: controlling the things we can control, and doing what it takes to sustain

21 YEARS OF DIVIDEND GROWTH



our long record of success. I'm very proud of, and truly grateful for, how well our employees are adapting to the new economic and energy realities.

FINANCIAL PERFORMANCE Despite the global financial crisis and economic slowdown, we successfully delivered on our 2008 financial goals with full-year ongoing earnings per share of $2.98. Our total shareholder return for the year was a negative 12.9 percent. We're not satisfied with a negative return, but it was better than most of our peers and much better than the equity market as a whole. We also maintained our investment-grade credit rating.

In the opening days of 2009, Progress Energy conducted two large, successful financings that signaled the confidence investors have in our stability and our future – even in these turbulent times. We raised more than $1.1 billion in capital on favorable terms in a 14.4 million-share stock sale and a $600 million bond sale.

As of February 2009, Progress Energy has paid a dividend for 250 consecutive quarters and has increased its dividend for 21 years in a row (50 of the last 55 years). That's a strong record of consistency and reliability – qualities that stand out even more now in a business world filled with so many reversals and betrayed expectations.

To make sure we hold down expenses and live within our means, we initiated in 2008 a more systematic effort to achieve sustainable efficiency improvements and productivity gains year after year. We have also adopted temporary belt-tightening measures, such as travel restrictions, to reduce discretionary spending until the economy improves. And we reorganized certain areas of the company and eliminated some jobs, in part because of the decrease in customer growth rates in Florida. Fortunately, we've been able to avoid across-the-board layoffs.

CUSTOMER AND OPERATIONAL FOCUS Our employees continue to provide reliable electric service to our 3.1 million customers in the Carolinas and Florida. Operational excellence is a core competency here, and we are among the industry leaders in safety each year. In 2008 we were named to the Dow Jones Sustainability North America Index for the fourth consecutive year, a sign of our commitment to environmental stewardship.

The reality is that it costs more today to produce electricity and provide electric service than it did just a few years ago due to higher fuel costs and

FINANCIAL HIGHLIGHTS

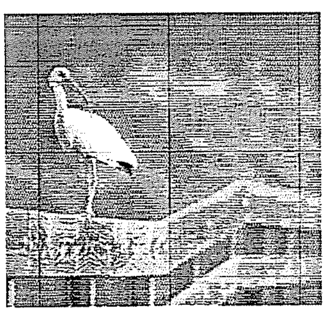
Years ended December 31 (in millions, except per share data)	2008	2007	2006
Financial Data			
Operating revenues	**$9,167**	$9,153	$8,724
Net income	**830**	504	571
Income from continuing operations	**773**	693	551
Ongoing earnings per common share*	**2.98**	2.72	2.44
Reported GAAP earnings per common share	**3.19**	1.97	2.28
Average common shares outstanding	**260**	256	250
Common Stock Data			
Return on average common stock equity (percent)	**9.59**	5.97	7.05
Book value per common share	**$33.13**	$32.55	$32.61
Market value per common share (closing)	**$39.85**	$48.43	$49.08

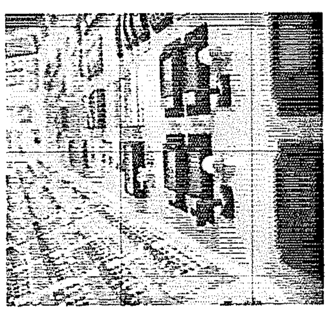
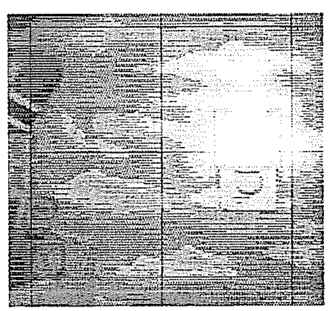
**See page 126 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*

new environmental policies as well as expansion of generating capacity and transmission facilities. We have had to raise our rates in the Carolinas and Florida in the last 12 months, which came at a particularly bad time given the economic downturn. We are working closely with customers to help them conserve energy and hold down the increases in their electric bills.

We know that successfully managing large infrastructure projects, such as nuclear and transmission construction as well as environmental retrofits, is critical. So we established a Project Management Center of Excellence last year to strengthen our already considerable expertise with these capital projects – to become more efficient, flexible and cost effective.

FORWARD-LOOKING INITIATIVES Securing our energy future requires a diverse, balanced strategy to meet the energy needs of a growing population and the emerging federal and state policies to reduce carbon emissions and climate change. Progress Energy's strategy includes aggressive energy efficiency and innovative alternative energy (such as solar and biomass projects), as well as state-of-the-art power plants to provide needed large-scale generating capacity. It's a portfolio



approach that leverages advances in nuclear plants and transformational technologies such as the Smart Grid and plug-in electric vehicles.

Growth has long been a hallmark of the areas we serve. North Carolina is the fastest-growing state east of the Mississippi River and the fourth-fastest in the United States. South Carolina is tenth. Florida's rapid population growth has flattened with the collapse of the housing market, but we expect our annual long-term customer growth rate there to be 2 percent to 3 percent once the economy rebounds.

At Progress Energy, we must lay the groundwork now to make sure we're ready to meet our service areas' energy needs a decade ahead. In this down economy, we reduced our 2009 capital spending plan by about $250 million, but we continue to fund our critical capital projects. It's important for us to keep making strategic investments that will produce value for our customers and investors.

During 2008, Florida regulators unanimously endorsed the need for our proposed two-unit nuclear plant in Levy County, Fla. We filed our federal license application in late 2007. In late 2008, we signed an engineering, procurement and construction agreement with Westinghouse and Stone & Webster, Inc. This nuclear plant will enable us to retire our two oldest coal-fired units in Florida – a major step in reducing carbon emissions.

Meeting U.S. energy demand growth while reducing carbon emissions is essential, but it will be hard and costly, and it will require sustained, coordinated efforts for decades to come. As a nation, we have not yet come to grips with the enormous scale of effort it will take: the capital investment, the technology research and development and the change in behavior of both energy producers and consumers.

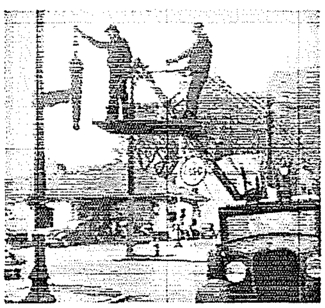
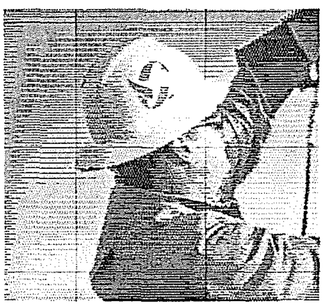
PERSEVERANCE AND ADAPTATION Along with everything else that happened in 2008, our company quietly but proudly celebrated its 100th anniversary. It also was my first full year as CEO. The last 100 years have included economic booms and busts, devastating wars, technological and social revolutions, disruptive natural disasters and energy crises, and a dramatic increase in population and consumer expectations. Through it all, our nation and company have endured, changed and become stronger.

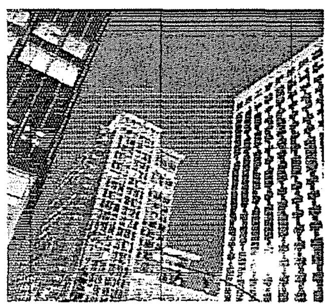
Now, in 2009, a deep economic recession is testing all Americans and every business and institution in our society. Whether you're a Progress Energy customer or investor, or a public official, you have reason to be confident in our company. We are determined to weather this economic storm and emerge stronger and better for the benefit of the many people who rely on us to be there for them – today and years into the future.

I appreciate your interest in our company and the support from our highly capable board of directors, leadership team and workforce.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2009



EXECUTIVE AND SENIOR OFFICERS

William D. Johnson
Chairman, President and Chief Executive Officer

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
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 – Nuclear Generation
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc.

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

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

FINANCIAL REPORT

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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, estimated capital requirements through the year 2011 and future financing plans; and d) "Other Matters" about our synthetic fuels tax credits, the effects of new environmental regulations, meeting anticipated demand in our regulated service territories, potential nuclear construction and changes in the regulatory environment.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the Energy Policy Act of 2005 (EPACT), the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and renewable energy portfolio standards and our ability to recover related eligible costs under cost-recovery clauses or base rates; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, regulatory and financial risks; the impact on our facilities and businesses from a terrorist attack; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; economic fluctuations and the corresponding impact on our customers, including downturns in the housing and consumer credit markets; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; 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 the Parent; the duration and severity of the current financial market distress that began in the third quarter of 2008; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; the impact that increases in leverage may have on us; our ability to maintain current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); the investment performance of our nuclear decommissioning trust funds; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in our filings with the United States Securities and Exchange Commission (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 it 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.

INTRODUCTION

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

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. Over the last several years we have reduced our business risk by exiting substantially all of our nonregulated businesses. Our two electric utilities operate in regulated retail utility markets in the southeastern United States and have access to attractive wholesale markets in the eastern United States, which we believe positions us well for long-term growth.

Consistently excelling in the daily fundamentals of our utility business, including safely and reliably generating and delivering power to our customers

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

Successfully implementing our balanced solution for a secure energy future

Our balanced solution is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provide a solid basis for slowing and reducing carbon dioxide (CO_2) emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation. First, we are expanding and enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. Second, we are actively engaged in a variety of alternative energy projects and are evaluating the feasibility of producing electricity from these and other sources. North Carolina's minimum renewable energy portfolio standard begins in 2012. On January 12, 2009, the Florida Public Service Commission (FPSC) approved a draft state renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020; the rule requires legislative ratification before implementation. Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating the best new generation options, including advanced design nuclear technology, gas-fired combined cycle and combustion turbines, and modernization of existing coal plants to use clean coal technology. The considerations that will factor into this decision include, but are not limited to, construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms that our state jurisdictions have implemented, or are in the process of implementing. See "Other Matters – Regulatory Environment" and Note 7 for additional information.

We are continuing to pursue new nuclear generation based on expectations of new federal climate policy as well as recognition of the need for new baseload generating capacity and better fuel diversity and energy security.

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

Maintaining constructive regulatory relations while confronting new energy realities

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

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

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Federal judicial actions during 2008 vacated mercury emissions regulations and remanded clean air regulations to the United States Environmental Protection Agency (EPA) for modification. Subsequent rule issuances and interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. We currently estimate that total future capital expenditures for the Utilities to comply with environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $580 million at PEC and $350 million at PEF through 2018, which corresponds to the latest emission reduction deadline.

In addition, growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other greenhouse gases. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. While state-level study groups are busy in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. See "Other Matters – Environmental Matters" for additional information.

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

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

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 21 consecutive years, and 33 of the last 34 years. We will strive to preserve our investment grade credit ratings so that we are positioned to accommodate the significant future demand expected at the Utilities.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities' earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies, cost control, and the timing of recovery of fuel costs and storm damage. The Utilities contributed $914 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2008. Partially offsetting the Utilities' segment profit contribution were losses of $141 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

Ongoing cost management initiatives have enabled us to offset some of the impact of the slowing economy and high cost pressures. The Utilities are allowed to recover prudently incurred fuel costs through the fuel portion of our rates, which are adjusted annually in each state. We attempt to mitigate rising fuel prices through our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity. Mitigating the impact of rising fuel prices benefits our cash flows, interest expense and leverage. Additionally, recovery of higher fuel costs negatively impacts customer satisfaction.

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

We expect total capital expenditures before potential nuclear construction to be approximately $2.2 billion, $2.1 billion and $2.0 billion for 2009, 2010 and 2011, respectively. If we determine to proceed with the construction of a new nuclear facility, we expect that our potential nuclear construction expenditures will range from $260 million to $560 million in 2009, $460 million to $660 million in 2010 and $750 million to $950 million in 2011. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentage of joint ownership. PEF has utilized, and anticipates continuing to utilize, nuclear cost-recovery mechanisms for nuclear preconstruction and construction cost financing available under Florida law. Subject to regulatory approval, capital investments that support load growth and comply with environmental regulations increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized, and create the basis for long-term earnings growth in the Utilities.

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

RESULTS OF OPERATIONS

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

Overview

FOR 2008 AS COMPARED TO 2007 AND 2007 AS COMPARED TO 2006

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

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

Partially offsetting these items were:

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

For the year ended December 31, 2007, our net income was $504 million, or $1.97 per share, compared to $571 million, or $2.28 per share, for the same period in 2006. For the year ended December 31, 2007, our income from continuing operations was $693 million compared to $551 million for the same period in 2006. The increase in income from continuing operations as compared to prior year was due primarily to:

- lower North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization expense at PEC;
- lower interest expense at the Parent due to reducing debt in late 2006;
- the cost incurred to redeem debt at the Parent in 2006;
- favorable weather at PEC;
- lower allocations of corporate overhead to continuing operations as a result of the 2006 divestitures;
- unrealized losses recorded on contingent value obligations (CVOs) during 2006;
- favorable AFUDC equity at the Utilities;
- favorable net retail customer growth and usage at the Utilities; and
- higher wholesale revenues at PEF.

Partially offsetting these items were:

- higher operation and maintenance (O&M) expenses at the Utilities primarily due to higher plant outage and maintenance costs and higher employee benefits;
- additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generation assets (See Note 7B);
- higher interest expense at PEF;
- the impact of the 2006 gain on sale of Level 3 Communications, Inc. stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- higher other operating expenses due to disallowed fuel costs at PEF.

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

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

Progress Energy Carolinas

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

The increase in profits for 2007 as compared to 2006 is primarily due to lower Clean Smokestacks Act amortization, the favorable impact of weather and favorable net retail customer growth and usage, partially offset by higher O&M expense related to plant outage and maintenance costs and employee benefit costs and additional depreciation expense associated with PEC's accelerated cost-recovery program for nuclear generating assets.

The revenue tables below present the total amount and percentage change of revenues excluding fuel. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, a portion of purchased power expenses and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with accounting principles generally accepted in the United States of America (GAAP). However, revenues excluding fuel and other pass-through revenues is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

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

PEC's revenues, excluding fuel and other pass-through revenues of $1.625 billion and $1.547 billion for 2008 and 2007, respectively, decreased $34 million. The decrease in revenues was due primarily to lower wholesale revenues, excluding fuel and other pass-through revenues, of $45 million and the $28 million unfavorable impact of weather, partially offset by the $34 million favorable impact of net retail customer growth and usage. The lower wholesale revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer.

The current recession in the United States has contributed to a slowdown in customer growth and usage in PEF's service territory (See "Progress Energy Florida – Revenues"). PEC has not been impacted by the recession as significantly as PEF. However, PEC has experienced some decline in the rate of residential and commercial sales growth. We cannot predict the severity of the recession, how long it may last or the extent to which it may impact PEC's revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates resulting from higher fuel and other recoverable costs.

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

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

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

Retail revenues increased 1.4 percent for 2008 despite a decrease in retail energy sales for the same period primarily due to the impact of increased fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs. Industrial electric energy sales decreased in 2008 compared to 2007, primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation, as well as a downturn in the lumber and building materials segment as a result of declines in residential construction.

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

Industrial electric energy sales decreased in 2007 compared to 2006 primarily due to the downward trends in textile manufacturing and residential construction previously discussed. The increase in industrial revenues for 2007 compared to 2006 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

EXPENSES

Fuel and Purchased Power

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

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

Fuel and purchased power expenses were $1.683 billion for 2007, which represents a $176 million increase compared to 2006. Fuel used in electric generation increased $208 million to $1.381 billion primarily due to a $156 million increase in fuel costs and a $54 million increase in deferred fuel expense. Fuel costs increased primarily due to a change in generation mix as the percentage of generation supplied by natural gas increased in response to plant outages and higher system requirements driven by favorable weather. Deferred fuel expense increased primarily due to the collection of fuel costs from customers that had been previously under-recovered. Purchased power expense decreased $32 million to $302 million compared to 2006. The decrease in purchased power is due to lower co-generation as a result of contract changes with one of PEC's co-generators.

Operation and Maintenance

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

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

Depreciation, Amortization and Accretion

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

Depreciation, amortization and accretion expense was $519 million for 2007, which represents a $52 million decrease compared to 2006. This decrease is primarily attributable to a $106 million decrease in the Clean Smokestacks Act amortization, partially offset by $37 million additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets (See Note 7B), an $11 million charge to reduce PEC's GridSouth regional transmission organization (RTO) development costs (See Note 7D) and the $7 million impact of depreciable asset base increases. We recorded $34 million of Clean Smokestacks Act amortization during 2007 compared to $140 million in 2006 (See Note 7B). We recorded $37 million of additional depreciation associated with the accelerated cost-recovery program for nuclear generating assets during 2007 compared to none in 2006.

Total Other Income, Net

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

Total other income, net was $37 million for 2007, which represents a $13 million decrease compared to 2006. This decrease is primarily due to the 2006 reclassification of $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). This decrease is partially offset by $6 million favorable AFUDC equity related to costs associated with eligible construction projects.

Total Interest Charges, Net

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

Total interest charges, net was $210 million for 2007, which represents a $5 million decrease compared to 2006. This decrease is primarily due to the $5 million impact of a decrease in average long-term debt and $3 million favorable AFUDC debt related to costs associated with eligible construction project costs, partially offset by $2 million higher interest related to higher variable rates on pollution control obligations.

Income Tax Expense

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

Progress Energy Florida

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

The decrease in profits for 2007 as compared to 2006 is primarily due to higher O&M expenses related to plant outage and maintenance costs and employee benefit costs, higher interest expense, higher other operating expense and higher depreciation and amortization expense excluding recoverable storm amortization, partially offset by favorable AFUDC and higher wholesale sales.

The revenue tables below present the total amount and percentage change of revenues excluding fuel and other pass-through revenues. Revenues excluding fuel and other pass-through revenues is defined as total electric revenues less fuel and other pass-through revenues. We consider revenues excluding fuel and other pass-through revenues a useful measure to evaluate PEF's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, revenues excluding fuel and other pass-through revenues is not defined under GAAP, and the presentation may not be comparable to other companies' presentation or more useful than the GAAP information provided elsewhere in this report.

REVENUES

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

(in millions)

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

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

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

PEF's revenues, excluding fuel and other pass-through revenues of $3.109 billion and $3.038 billion for 2007 and 2006, respectively, increased $39 million. The increase in revenues was primarily due to increased wholesale revenues, favorable net retail customer growth and usage, and other miscellaneous service revenues. Wholesale revenues, excluding fuel and other pass-through revenues, increased $29 million primarily due to the $21 million impact of increased capacity under contract with a major customer. The favorable net retail customer growth and usage impact of $7 million was driven by a net 23,000 increase in the average number of customers for 2007, compared to 2006, partially offset by lower average usage per customer. Other miscellaneous service revenues increased primarily due to increased electric property rental revenues of $6 million.

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

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

Industrial electric energy revenues and sales decreased in 2007 compared to 2006 primarily due to a change in the terms of an agreement with a major customer.

EXPENSES

Fuel and Purchased Power

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

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

Fuel and purchased power expenses were $2.646 billion in 2007, which represents a $45 million increase compared to 2006. Purchased power expense increased $116 million to $882 million compared to 2006. This increase is primarily due to a $123 million increase in current year purchased power costs, partially offset by a $6 million decrease in the recovery of deferred capacity costs. The increased current year purchased power costs are a result of higher interchange purchases of $87 million and higher capacity costs of $43 million primarily due to new contracts. Fuel used in electric generation decreased $71 million to $1.764 billion due to a $323 million decrease in deferred fuel expense partially offset by a $252 million increase in 2007 fuel costs due primarily to an increase in oil and natural gas prices. Deferred fuel expense was higher in 2006 primarily due to the collection of fuel costs from customers that had been previously under-recovered.

Operation and Maintenance

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

O&M expense was $834 million in 2007, which represents a $150 million increase compared to 2006. The increase is primarily due to $46 million related to an increase in storm damage reserves from the one-year extension of the storm surcharge, which began August 2007 (See Note 7C) and $40 million related to higher ECRC and energy conservation cost recovery clause (ECCR) costs. Additionally, the increase is due to $27 million higher plant outage and maintenance costs and $12 million higher employee benefit costs. The higher employee benefit costs are primarily due to the impact from changes in stock-based compensation plans implemented in 2007 and higher relative employee incentive goal achievement in 2007 compared to 2006. The ECRC, ECCR and storm damage reserve expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates increased $63 million compared to the same period in 2006.

Depreciation, Amortization and Accretion

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

Depreciation, amortization and accretion expense was $366 million for 2007, which represents a decrease of $38 million compared to 2006, primarily due to $47 million lower amortization of unrecovered storm restoration costs and $5 million lower software and franchise amortization, partially offset by the $13 million impact primarily related to depreciable asset base increases and a $7 million write-off of leasehold improvements, primarily related to vacated office space. As noted above, storm restoration costs amortization had no material impact on earnings.

Other

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

Total Other Income, Net

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

Total other income, net was $48 million for 2007, which represents a $20 million increase compared to 2006. This increase is primarily due to $24 million favorable AFUDC equity related to eligible construction project costs, partially offset by $5 million lower interest income on unrecovered storm restoration costs.

Total Interest Charges, Net

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

Total interest charges, net was $173 million in 2007, which represents an increase of $23 million compared to 2006. The increase in interest charges is primarily due to the $10 million impact of an increase in average long-term debt, the $7 million impact of interest on over-recovered fuel costs, $6 million increase in interest on income tax related items and $2 million increase related to the disallowed fuel costs (See Note 7C). These increases are partially offset by $7 million favorable AFUDC debt related to costs associated with eligible construction project costs

Income Tax Expense

Income tax expense was $181 million, $144 million and $193 million in 2008, 2007 and 2006, respectively. The $37 million income tax expense increase in 2008 compared to 2007 is primarily due to the $40 million impact of higher pre-tax income compared to the prior year, $6 million benefit related to the closure of certain federal tax years and positions in the prior year, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's most recent base rate agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense. The $49 million income tax expense decrease in 2007 compared to 2006 is primarily due to the $23 million impact of lower pre-tax income, the $16 million impact of tax adjustments and the $9 million impact of favorable AFUDC equity discussed above. The tax adjustments are primarily related to the $10 million impact of changes in income tax estimates and the $6 million favorable impact related to the closure of certain federal tax years and positions.

Corporate and Other

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a separate business segment. Corporate and Other expense is summarized below:

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

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

Other interest expense, which includes elimination entries, decreased $54 million for 2007 compared to 2006 primarily due to the $86 million impact of the $1.7 billion reduction in debt at the Parent during 2006, partially offset by a $45 million decrease in the interest allocated to discontinued operations. The decrease in interest expense allocated to discontinued operations resulted from the allocations of interest expense in 2006 for operations that were sold in 2006. Interest expense allocated to discontinued operations was $13 million and $58 million for 2007 and 2006, respectively.

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate (See Note 15). At December 31, 2008 and 2007, the CVOs had a fair value of $34 million and at December 31, 2006, the CVOs had a fair value of $32 million. Progress Energy recorded unrealized losses of $2 million and $25 million for 2007 and 2006, respectively, to record the changes in fair value of the CVOs, which had average unit prices of $0.35 at December 31, 2008 and 2007 and $0.33 at December 31, 2006.

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

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

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

For 2007, other expense was $18 million compared to $64 million in 2006. The $46 million decrease is primarily due to the $59 million pre-tax loss on redemptions of debt at the Parent in 2006 (See Note 20) and the $30 million decrease in the allocation of corporate overhead as a result of the divestitures completed during 2006. These decreases are partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 Communications, Inc. stock subsequent to the sale of PT LLC in 2006 (See Note 3F) and the $14 million increase in interest income on temporary investments due to proceeds from the sale of nonregulated businesses.

Discontinued Operations

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

TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. The coal terminals had a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets.

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007. All periods have been restated to reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

Terminals and synthetic fuels businesses generated net earnings from discontinued operations of $19 million and $83 million for the years ended December 31, 2008 and 2007, respectively. Net losses from discontinued operations for Terminals and synthetic fuels businesses were $37 million for the year ended December 31, 2006.

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

The change in net loss from discontinued operations of $37 million for the year ended December 31, 2006, to net earnings from discontinued operations of $83 million for the year ended December 31, 2007, is primarily due to increased tax credits generated due to higher production of coal-based solid synthetic fuels, mark-to-market gain on derivative contracts in 2007 and the impairment of synthetic fuels assets recorded in 2006. These favorable items are partially offset by an increase in the tax credit reserve due to the increase in production and the change in the relative oil prices, which indicated a higher estimated phase-out of tax credits, and lower margins due to the increase in coal-based solid synthetic fuels production.

COAL MINING BUSINESSES

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

On May 1, 2006, we sold certain net assets of three of our coal mining businesses for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million for the sale of these assets.

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

CCO – GEORGIA OPERATIONS

On March 9, 2007, our subsidiary PVI entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested included approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the nonregulated generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax loss and reversed $18 million after tax of the impairment recorded in 2006, respectively.

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

CCO's operations generated net losses from discontinued operations of $3 million, $283 million and $57 million in 2008, 2007 and 2006, respectively. Net losses from discontinued operations in 2007 primarily represent the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to dedesignated natural gas hedges. These hedges were dedesignated because management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet of natural gas would be fulfilled. Therefore, cash flow hedge accounting was discontinued. Net losses from discontinued operations in 2006 primarily represent the $64 million pre-tax impairment loss ($42 million after-tax) on goodwill recognized in the first quarter of 2006.

NATURAL GAS DRILLING AND PRODUCTION

On October 2, 2006, we sold our natural gas drilling and production business (Gas) for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd., Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels. Proceeds from the sale were used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

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

CCO – DESOTO AND ROWAN GENERATION FACILITIES

On May 8, 2006, we entered into definitive agreements to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan), including certain existing power supply contracts to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes.

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006. DeSoto and Rowan operations generated combined net earnings from discontinued operations of $10 million for the year ended December 31, 2006.

PROGRESS TELECOM, LLC

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

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax gain on disposal of $28 million during the year ended December 31, 2006. Net losses from discontinued operations for PT LLC were $2 million for the year ended December 31, 2006.

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transported coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the years ended December 31, 2008 and 2007, we recorded an additional gain of $1 million and $2 million, respectively, primarily related to the expiration of indemnifications.

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

PROGRESS RAIL

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

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Impact of Utility Regulation

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

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. If an impairment indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred. At December 31, 2008 and 2007, the carrying value of our total utility plant, net was $18.293 billion and $16.605 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

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

The adoption of SFAS No. 143 and FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71).

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

Nuclear decommissioning AROs represent 96 percent of Progress Energy's total AROs at December 31, 2008. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized

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

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

Goodwill

As discussed in Note 8, we account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2008 and 2007, each of which indicated no impairment. If the fair values for the utility segments were lower by 10 percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2008 and 2007, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

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

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

Unbilled Revenue

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. At December 31, 2008 and 2007, amounts recorded as receivables on the Consolidated Balance Sheets related to unbilled revenues were $182 million and $175 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, we account for the effects of income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), and FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48).

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

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material. In accordance with FIN 48, the uncertainty and judgment involved in the determination and filing of income taxes 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 for the application of FIN 48: recognition of the tax benefit based on a "more-likely-than-not" threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority.

Pension Costs

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

Due to a slight increase in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to calculate the present value of future benefit payments, we increased the discount rate to approximately 6.30% at December 31, 2008, from approximately 6.20% at December 31, 2007, which will not significantly affect 2009 pension costs. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Consistent with general market conditions, our plan assets performed poorly in 2008 with returns of approximately (32)%. That negative asset performance will result in increased pension costs in 2009, all other factors remaining constant. In addition, contributions to pension plan assets in 2008 and 2009 will result in decreased pension costs in 2009 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2009 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2009 will be $85 million to $95 million, compared with $14 million recognized in 2008.

We have pension plan assets with a fair value of approximately $1.3 billion at December 31, 2008. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 25 basis point change in the expected rate of return for 2008 would have changed 2008 pension costs by approximately $5 million.

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

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

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

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

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

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

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

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

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

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

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

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

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

Historical for 2008 as Compared to 2007 and 2007 as Compared to 2006

CASH FLOWS FROM OPERATIONS

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

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

Net cash provided by operating activities for 2007 decreased when compared with 2006. The $749 million decrease in operating cash flow was primarily due to $472 million in income tax impacts, largely driven by income tax payments related to the sale of Gas; the $347 million payment made to exit the Georgia Contracts (See Note 3C); a $279 million decrease in the recovery of fuel costs; and $65 million in premiums paid for derivative contracts in our synthetic fuels businesses. These impacts were partially offset by a $157 million decrease in inventory purchases in 2007, primarily related to coal purchases at the Utilities; $106 million of working capital changes related to the divestiture of CCO; and $47 million in net refunds of cash collateral previously paid to counterparties on derivative contracts in 2007 compared to $47 million in net cash payments in 2006 at PEF. The decrease in recovery of fuel costs is due to a $335 million decrease at PEF driven by the 2006 recovery of previously under-recovered fuel costs, partially offset by a $56 million increase in the recovery at PEC driven by the 2007 recovery of previously under-recovered fuel costs.

In 2008, 2007 and 2006, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries.

INVESTING ACTIVITIES

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

Property additions at the Utilities, including nuclear fuel, were $2.534 billion and $2.199 billion in 2008 and 2007, respectively, or approximately 100 percent of consolidated capital expenditures in both 2008 and 2007. Capital expenditures at the Utilities are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

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

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $675 million in 2007 and $1.657 billion in 2006, cash used in investing activities increased by $602 million in 2007 as compared to 2006. The increase in 2007 was primarily due to a $539 million increase in gross property additions at the Utilities, primarily at PEF, and a $114 million increase in nuclear fuel additions, partially offset by a decrease in property additions at our diversified businesses, most of which have been discontinued or abandoned. At PEC, utility property additions primarily related to an increase in spending for compliance with the Clean Smokestacks Act. At PEF, the increase in utility property additions was primarily due to environmental compliance projects, repowering the Bartow plant to more efficient natural gas-burning technology, which will not be completed until 2009, and nuclear and transmission projects, partially offset by lower spending on energy system distribution projects and at the Hines Unit 4 facility.

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

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

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

FINANCING ACTIVITIES

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

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

The increase in net cash provided by financing activities for 2007 compared to 2006 primarily related to the issuance of $750 million in long-term debt at PEF and the $1.7 billion reduction in holding company debt in 2006.

Our financing activities are described below.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.
- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding money pool balance and for general corporate purposes.

2008

- On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.
- On March 12, 2008, PEC and PEF amended their RCAs with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA is now scheduled to expire on June 28, 2011, and PEF's RCA is now scheduled to expire on March 28, 2011 (See "Credit Facilities and Registration Statements").
- On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D,

due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

- On April 14, 2008, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").
- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.
- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.
- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. A portion of the RCA borrowings was repaid with proceeds from the January 2009 equity issuance, and we will continue to monitor the commercial paper and short-term credit markets to determine when to repay the remaining balance of the RCA loan, while maintaining an appropriate level of liquidity.
- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2008, the dividends paid on common stock were approximately $642 million.

2007

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

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. The net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds were used to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006, effectively terminating our $800 million 364-day credit agreement as discussed below.

- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006.
- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility.
- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility.
- On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.
- On November 1, 2006, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $60 million of its 7.17% Medium-Term Notes with available cash on hand.
- On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions
- Progress Energy issued approximately 4.2 million shares of common stock resulting in approximately $185 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and equity incentive plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million issued for the 401(k) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 million.

Future Liquidity and Capital Resources

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

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2008, 2007 and 2006. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. As of December 31, 2008, we have carried forward $799 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

The absence of cash flow from divested businesses is not expected to impact our future liquidity or capital resources as these businesses in the aggregate have been largely cash flow neutral over the last several years.

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

We issue commercial paper to meet short-term liquidity needs. As a result of financial and economic conditions in 2008, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. In November 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. A portion of the RCA was repaid with proceeds from the January 2009 equity issuance, and we will continue to monitor the commercial paper and short-term credit markets to determine when to repay the remaining balance of the RCA loan, while maintaining an appropriate level of liquidity. If liquidity conditions deteriorate further and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include extending the term and amount of our borrowings under the Parent's RCA, issuing short-term floating rate notes and/or issuing long-term debt.

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

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

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

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

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under "Other Matters – Increasing Energy Demand" will require the Utilities to make significant capital investments. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation. As discussed in "Environmental Matters – Environmental Compliance Cost Estimates," the Utilities are continuing construction of in-process emission control projects. On December 18, 2008, PEF and the Florida Department of Environmental Protection (FDEP) announced an agreement under which PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and complete construction of its emission control projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5). CR1 and CR2 will be retired after the second proposed Levy nuclear unit completes its first fuel cycle, which is anticipated to be around 2020

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause. Due to commodity price changes since December 31, 2008, we have posted additional collateral with counterparties. At February 23, 2009, we had posted approximately

$580 million of cash collateral compared to $340 million of cash collateral posted at December 31, 2008. The majority of our financial hedge agreements will settle in 2009 and 2010. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity.

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

REGULATORY MATTERS AND RECOVERY OF COSTS

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

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

Among other provisions, the North Carolina and South Carolina state energy laws provide mechanisms for recovery of certain baseload generation construction costs and expand annual fuel clause mechanisms so that additional costs may be recovered annually. On February 29, 2008, the North Carolina Utilities Commission (NCUC) issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. Rates for the DSM and energy-efficiency clause and the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) clause will be set based on projected costs with true-up provisions.

PEC Cost-Recovery Clause

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

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

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

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007.

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

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

PEF Cost-Recovery Clause

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

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

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

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

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers, which were estimated to be $22 million at December 31, 2008. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve its integrated strategy to address compliance with the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) through the ECRC (See "Other Matters – Environmental Matters" for discussion regarding the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

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

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

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

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

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2008.

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

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

[a] Expenditures for potential nuclear construction are net of AFUDC-borrowed funds and include land, development, licensing, equipment and associated transmission. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership.

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

Regulated capital expenditures for 2009, 2010 and 2011 in the table above include approximately $380 million, $230 million and $120 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2009, 2010 and 2011 include $80 million, $150 million and $120 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2009 and 2010 include $300 million and $80 million, respectively, at PEF. PEF does not have forecasted environmental compliance capital expenditure in 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

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

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2008 and 2007, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. At December 31, 2007, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our RCAs and available capacity at December 31, 2008:

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

[a] In February 2009, the Parent repaid $100 million of its outstanding RCA borrowings.
[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had a total amount of $30 million of letters of credit issued, which were supported by the RCA.

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

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

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2008. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2008, the calculated ratios pursuant to the terms of the agreements are as disclosed in Note 11.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees.

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

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

Both PEC and PEF can issue first mortgage bonds under their respective first mortgage bond indentures. At December 31, 2008, PEC and PEF could issue up to $4.1 billion and $1.7 billion of first mortgage bonds, respectively, based on property additions and $1.5 billion and $256 million, respectively, based upon retirements of previously issued first mortgage bonds. On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds will be used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. Therefore, given the effect of the January 2009 issuance and the application of proceeds, PEC could issue up to $1.3 billion of first mortgage bonds based upon retirements of previously issued first mortgage bonds.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

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

CREDIT RATING MATTERS

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

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Parent			
Outlook	Stable	Stable	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F-2
PEC			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB+	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	A-
PEF			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB+	A-
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	A-	A+
Senior unsecured debt	A3	BBB+	A
Preferred stock	Baa2	BBB-	A-
FPC Capital I			
Quarterly Income Preferred Securities[a]	Baa2	BBB-	A

[a] Guaranteed by the Parent and Florida Progress.

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

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2008, we have issued $402 million of guarantees for future financial or performance assurance. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At December 31, 2008, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

Market Risk and Derivatives

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

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2008, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 11)	$10,716	$–	$1,406	$1,875	$7,435
Interest payments on long-term debt[b]	9,000	623	1,163	941	6,273
Capital lease obligations[c] (See Note 22B)	726	34	69	87	536
Operating leases[c] (See Note 22B)	1,367	48	52	117	1,150
Fuel and purchased power[d] (See Note 22A)	22,657	3,608	5,349	3,554	10,146
Other purchase obligations[e] (See Note 22A)	9,836	1,151	3,098	3,001	2,586
Minimum pension funding requirements[f]	1,162	130	426	235	371
Other postretirement benefits[g] (See Note 16A)	494	40	88	98	268
Uncertain tax positions[h] (See Note 14)	–	–	–	–	–
Other commitments[i]	119	13	27	26	53
Total	$56,077	$5,647	$11,678	$9,934	$28,818

[a] Our maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.
[b] Interest payments on long-term debt are based on the interest rate effective at December 31, 2008.
[c] Amounts include certain related executory cost commitments.
[d] Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through cost-recovery clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
[e] Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership.
[f] Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.
[g] Represents projected benefit payments for a total of 10 years related to our postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and the general health care cost trend.
[h] Uncertain tax positions of $104 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2009.
[i] By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

Synthetic Fuel Tax Credits

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year were phased out when annual average market prices for crude oil exceeded certain prices. The synthetic fuels tax credit program expired at the end of 2007. Because we abandoned our majority-owned facilities and our other synthetic fuels operations ceased in late December 2007, we reclassified the operations of our synthetic fuels businesses as discontinued operations in the fourth quarter of 2007.

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

Section 29 provided that if the average wellhead price per barrel for unregulated domestic crude oil for the year (Annual Average Price) exceeded a certain threshold value (the Threshold Price), the amount of Section 29/45K tax credits was reduced for that year. Also, if the Annual Average Price exceeded the price per barrel of unregulated domestic crude oil at which the value of Section 29/45K tax credits was fully eliminated (Phase-out Price), the Section 29/45K tax credits were eliminated for that year. The Threshold Price and the Phase-out Price were adjusted annually for inflation.

When the Annual Average Price fell between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits were reduced depended on where the Annual Average Price fell in that continuum. The Department of the Treasury calculated the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency. Based on the respective Annual Average Price, our synthetic fuels tax credits generated during 2007 and 2006 were reduced by 67 percent and 33 percent, or approximately $138 million and $35 million, respectively.

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

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

Regulatory Environment

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

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

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

During the 2008 session, the Florida legislature passed comprehensive energy legislation, which became law on June 26, 2008. The legislation includes provisions that would, among other things, (1) help enhance the ability to cost-effectively site transmission lines; (2) require the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification in 2009; (3) direct the FDEP to develop rules establishing a cap-and-trade program to regulate greenhouse gas emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification by the legislature; (4) establish a new Florida Energy and Climate Commission as the principal governmental body to develop energy and climate policy for the state and to make recommendations to the governor and legislature on energy and climate issues; and (5) require the FPSC to analyze utility revenue decoupling and provide a report and recommendation to the governor and legislature by January 1, 2009. The FPSC concluded and recommended to the governor and legislature that no specific revenue decoupling program needs to be, or should be, implemented at this time. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until the rulemaking processes are completed, we cannot predict the costs of complying with the law.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of greenhouse gas emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of greenhouse gases for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions.

The Energy and Climate Action Team appointed by the governor developed recommendations through a stakeholder process and submitted its final report to the governor on October 15, 2008. The report's recommendations encourage the consideration of a cap-and-trade approach to reduce the state's greenhouse emissions and the development and implementation of energy-efficiency and conservation measures, a climate registry and a renewable portfolio standard (Florida RPS) of 20 percent by 2020. The FDEP's first workshop on the greenhouse gas cap-and-trade rulemaking was held December 11, 2008. The rulemaking is expected to continue through 2009, and the rule requires legislative ratification before implementation. The executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from on-site renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). The FPSC has held meetings regarding the renewable portfolio standard, and the FPSC staff drafted a Florida RPS that would require that 20 percent of electricity produced in the state come from renewable resources by 2041. On January 12, 2009, the FPSC approved a draft Florida RPS rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida RPS rule to the Florida legislature in February 2009. The legislature will review, ratify as is, make revisions, or decide not to have a Florida RPS rule at all. We cannot predict the outcome of this matter.

We cannot predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in "Increasing Energy Demand," includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility. PEF has agreed that CR1 and CR2 will cease to be operated as coal-fired units by December 31, 2020. This date assumes timely licensing, construction and commencement of commercial operation of PEF's proposed new Levy Units 1 and 2. The retirement of CR1 and CR2 as coal-fired units is contingent upon completion of the first fuel cycle for Levy Unit 2. PEF shall advise the FDEP of any developments that would delay the retirement of CR1 and CR2 beyond the completion of the first fuel cycle for Levy Unit 2.

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. The law includes provisions for NC REPS, expansion of the definition of the traditional fuel clause and recovery of the costs of new DSM and energy-efficiency programs through an annual DSM clause.

On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. These rules provide filing requirements associated with the legislation. The order required PEC to submit its first annual NC REPS compliance plan as part of its integrated resource plan, which was filed on September 2, 2008. Under the new rules, beginning in 2009, PEC will also be required to file an annual NC REPS compliance report demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC will pursue a third-party REC tracking system, but will not develop or require participation in a REC trading platform at this time. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the NC REPS clause will be set based on projected costs with true-up provisions. In 2008, PEC filed for NCUC approval of multiple DSM and energy-efficiency programs. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the DSM and energy-efficiency filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

Legal

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

Increasing Energy Demand

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

We are actively pursuing expansion of our DSM, energy-efficiency and conservation programs as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. Our energy-efficiency program provides simple, low-cost options for residential customers to reduce energy use, promotes home energy checks, provides tools and programs for large and small businesses to minimize their energy use and provides an interactive Internet Web site with online calculators, programs and efficiency tips.

We are actively engaged in a variety of alternative energy projects, including producing electricity from swine waste and other plant or animal sources, solar, hydrogen, biomass and landfill-gas technologies. We are evaluating the feasibility of producing electricity from these and other sources.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants. In 2007, PEC announced a two-year moratorium on constructing new coal-fired plants while pursuing expansion of energy-efficiency and conservation programs. If PEC proceeds with construction of a new nuclear plant, the new plant would not be online until at least 2019 (See "Nuclear" below).

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

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

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

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the Internal Revenue Service (IRS) provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before

January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

NUCLEAR

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

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

Potential New Construction

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed, or accepted for review, the Harris application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On June 4, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene may be filed within 60 days of the notice by anyone whose interest may be affected by the proposed license and who wishes to participate as a party in the proceeding. One petition to intervene was filed with the NRC within the 60-day notice period. We cannot predict the outcome of this matter. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019 (See "Increasing Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors. The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. If we receive timely approval from the NRC and applicable state agencies, and if the decisions to build are made, safety-related construction activities could begin as early as 2012, and a new plant could be operational in the 2016 to 2018 time frame (See "Increasing Energy Demand" above). On October 6, 2008, the NRC docketed, or accepted for review, the Levy nuclear project application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On December 8, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene may be filed within 60 days of the notice by anyone whose interest may be affected by the proposed license and who wishes to participate as a party in the proceeding. One petition to intervene was filed with the NRC within the 60-day notice period. We cannot predict the outcome of this matter.

In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF's requests to change the comprehensive land use plan. On May 29, 2008, the Florida Department of Community Affairs (FDCA) issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

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

In accordance with provisions of Florida's energy legislation enacted in 2006, the FPSC ordered new rules in December 2006 that would allow investor-owned utilities such as PEF to request recovery of certain planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balance on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of the proposed Levy nuclear project. PEF filed the petition to assist the FPSC in the timely and adequate review of the projects costs recoverable under the FPSC nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for the Levy nuclear project, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the FPSC nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor. PEF will be a participant in the annual nuclear cost-recovery proceeding, which was opened by the FPSC on January 5, 2009. The proceeding will occur throughout the year with an order expected by the end of 2009.

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

In 2007, the South Carolina legislature ratified new energy legislation, which includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. In 2007, the North Carolina legislature also passed new energy legislation, which authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and removes the requirement that a public utility prove financial distress before it may include construction work in progress in rate base and adjust rates, accordingly, in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

Spent Nuclear Fuel Matters

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca

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

On October 19, 2007, the DOE certified the regulatory compliance of the document database that will be used by all parties involved in the federal licensing process for the Yucca Mountain facility. The NRC did not uphold the DOE's prior certification in 2004 in response to challenges from the state of Nevada. The state again is expected to challenge the DOE's certification process. The DOE has stated that the earliest date the repository may be able to start accepting spent nuclear fuel is 2020. The Utilities cannot predict the outcome of this matter.

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

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

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

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

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

Environmental Matters

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

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both

PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 21A.

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

AIR QUALITY AND WATER QUALITY

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

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In March 2008, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately \$1.5 billion to \$1.6 billion at the time of the filing. The increase in estimated total capital expenditures from the original 2002 estimate of \$813 million is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are continuing to evaluate various design, technology and new generation options that could change expenditures required by the Clean Smokestacks Act. Changes in projected fuel sources may require us to incur costs, which are not currently estimable, to install additional controls subsequent to 2013 in order to remain compliant with the requirements of the Clean Smokestacks Act. O&M expenses will significantly increase due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. Recent legislation in North Carolina and South Carolina expanded the traditional fuel clause to include the annual recovery of reagents and certain other costs; all other O&M expenses are currently recoverable through base rates. See discussion regarding future recovery of costs to comply with the Clean Smokestacks Act in Note 7B. We cannot predict the outcome of this matter.

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

Clean Air Interstate Rule

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

PEF participated in a coalition of Florida utilities that filed a challenge to the CAIR as it applied to Florida (PEF withdrew from the coalition during the fourth quarter of

2008). On July 11, 2008, the D.C. Court of Appeals issued its decision on multiple challenges to the CAIR, including the Florida challenge, which vacated the CAIR in its entirety. On September 24, 2008, petitions for rehearing were filed by several parties. On October 21, 2008, the D.C. Court of Appeals issued an order directing petitioners to address (1) whether any party is seeking to vacate the CAIR, and (2) whether the court should stay its mandate until the EPA promulgates a revised rule. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The outcome of the additional proceedings cannot be predicted.

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

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

Clean Air Mercury Rule

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that set mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encouraged a cap-and-trade approach to achieving those caps and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. Sixteen states subsequently petitioned for a review of the EPA's determination confirming the delisting. On February 8, 2008, the D.C. Court of Appeals decided in favor of the petitioners and vacated the delisting determination and the CAMR. On March 24, 2008, the EPA and the Utility Air Regulatory Group filed petitions for rehearing by the full court of appeals, which were denied on May 20, 2008. On September 17, 2008, the Utility Air Regulatory Group filed a petition for writ of certiorari with the U.S. Supreme Court with regard to the decision that vacated the CAMR. On October 17, 2008, the EPA filed a similar petition and subsequently withdrew it on January 29, 2009. The Utility Air Regulatory Group's petition for writ of certiorari was denied on February 23, 2009. The three states in which the Utilities operate adopted mercury regulations implementing the CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR and any review granted by the Supreme Court will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

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

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

Compliance Strategy

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

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

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR through the ECRC (see discussion above regarding the vacating of the CAMR and remanding of the CAIR). On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote and Crystal River plants. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with the CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy. On June 1, 2007, PEF filed a supplemental petition for approval of its recommended compliance plan and associated contracts and recovery of costs for air pollution control projects. The estimated capital cost for the recommended plan was $1.26 billion in the June 1, 2007 filing. The increase from the estimates filed in March 2006 is primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. On April 2, 2008, PEF filed a petition for approval true-up of final 2007 environmental costs and a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. The following table contains information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the tables exclude AFUDC. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. Our estimated costs to comply with the CAVR prior to the July 11, 2008 D.C. Court of Appeals' decision regarding CAIR were approximately $100 million at PEC. Our previous estimate of

$1.0 billion to comply with the CAVR at PEF related primarily to installation of control equipment at CR1 and CR2, which we subsequently have decided to retire as coal-fired units. The timing and extent of the costs for future projects will depend upon final compliance strategies.

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2008
Clean Smokestacks Act	2002–2013	$1,500–1,600	$1,007
In-process CAIR projects[a]	2005–2010	1,200	847
CAVR[b]	–2017	–	–
Mercury regulation[c]	2006–2017	–	5
Total air quality		2,700–2,800	1,859
Clean Water Act Section 316(b)[d]		–	–
Total air and water quality		$2,700–2,800	$1,859

[a] 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."

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

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

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

To date, under the first phase of Clean Smokestacks Act emission reductions, all environmental compliance projects at PEC's Asheville, Lee and Roxboro plants have been placed in service. The remaining first-phase project at one of PEC's largest plants, Mayo, is under construction and is expected to be completed in 2009. The remaining projects to comply with the second phase of emission reductions, which are smaller in scope, have not yet begun. These estimates are conceptual in nature and subject to change. In 2008, PEC determined that its in-process CAIR project did not yield the desired compliance results and decided not to pursue completion of the project. Additional compliance projects requiring material environmental compliance costs may be implemented in the future.

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

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

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On March 16, 2006, the EPA issued a final response denying the petition. The EPA's rationale for denial was that compliance with the CAIR would reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. On June 26, 2006, the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial of the Section 126 petition; that appeal was held in abeyance pending resolution of the appeal of the CAIR then pending before the same court. On July 11, 2008, the D.C. Court of Appeals vacated the CAIR. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. On the basis of these developments, the appeal of EPA's denial of North Carolina's Section 126 petition was resumed and briefing on the merits has been completed. Oral argument is scheduled for March 12, 2009. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On September 20, 2006, the EPA announced changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter, including a new 24-hour standard for particulate matter less than 2.5 microns in diameter, which lowered the standard from 65 micrograms per cubic meter to 35 micrograms per cubic meter In addition, the EPA decided not to establish a standard for particulate matter between 2.5 and 10 microns in diameter and eliminated the annual standard for particulate matter less than 10 microns in diameter, but retained the 24-hour standard for particulate matter less than 10 microns in diameter. These changes did not result in designation of any additional nonattainment areas in PEC's or PEF's service territories. Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. The outcome of this matter cannot be predicted.

On March 12, 2008, the EPA announced changes to the NAAQS for ground-level ozone. The EPA revised the 8-hour primary and secondary standards from 0.08 parts per million to 0.075 parts per million. Depending on air quality improvements expected over the next several years as current federal requirements are implemented, additional nonattainment areas may be designated in PEC's and PEF's service territories. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The outcome of this matter cannot be predicted.

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

New Source Review

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

Water Quality

1. General

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

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

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

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA. On July 9, 2007, the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. On December 2, 2008, the U.S. Supreme Court heard arguments related to whether the EPA is authorized to compare costs with benefits in determining the "best technology available for minimizing adverse environmental impact" at cooling water intake structures. As a result of these developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol. Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other greenhouse gases. The Obama administration has agreed to review whether or not CO_2 emissions from coal-fired power plants should be regulated. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. While state-level study groups are active in all three of our jurisdictions, we continue to believe that this is an issue that requires a national policy framework – one that provides certainty and consistency. Our balanced solution is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation as discussed under "Other Matters – Increasing Energy Demand." In addition to a report issued in 2006, we issued an updated report on global climate change in the second quarter of 2008, which further evaluates and states our position on this dynamic issue. The outcome of this matter cannot be predicted.

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate greenhouse gas emissions that would be presented to the legislature no earlier than January 2010.

On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. On April 2, 2008, 18 states and 11 environmental groups filed an action in the D.C. Court of Appeals against the EPA Administrator seeking an order requiring the EPA to make a determination within 60 days of whether greenhouse gas emissions endanger public health and welfare. The D.C. Court of Appeals denied the petition on June 26, 2008. On July 11, 2008, the EPA issued an Advance Notice of Proposed Rulemaking inviting public comment on the issues and options that should be considered in development of comprehensive greenhouse gas regulation under the Clean Air Act. Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review its earlier denials of waiver requests by states to regulate CO_2 emissions from vehicles. The impact of these developments cannot be predicted.

New Accounting Standards

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

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

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

Interest Rate Risk

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

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

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

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

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

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

The following tables provide information at December 31, 2008 and 2007, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and Florida Progress-obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2009 to 2013 and thereafter and the related fair value. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

(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] $250 million is for anticipated 10-year debt issue hedge maturing on March 1, 2019, and requires mandatory cash settlement on March 1, 2009. The remaining $200 million is for anticipated 10-year debt issue hedge maturing on April 1, 2019, and requires mandatory cash settlement on April 1, 2009.
[c] Rate is 3-month LIBOR, which was 1.425% at December 31, 2008.

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

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

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

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

(dollars in millions) December 31, 2007	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value December 31, 2007
Fixed-rate long-term debt	$427	$400	$306	$1,000	$950	$4,865	$7,948	$8,192
Average interest rate	6.67%	5.95%	4.53%	6.96%	6.67%	6.03%	6.20%	
Variable-rate long-term debt	$450	–	$100	–	–	$861	$1,411	$1,411
Average interest rate	5.27%	–	5.69%	–	–	4.45%	4.80%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$294
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[b]	$200	–	–	–	–	–	$200	$(12)
Average pay rate	5.41%	–	–	–	–	–	5.41%	
Average receive rate	(c)	–	–	–	–	–	(c)	

[a] FPC Capital I – Quarterly Income Preferred Securities
[b] $100 million was for anticipated 10-year debt issue hedge maturing on April 1, 2018, and required mandatory cash settlement on April 1, 2008. The remaining $100 million was for anticipated 30-year debt issue hedge maturing on April 1, 2038, and required mandatory cash settlement on April 1, 2008.
[c] Rate was 3-month LIBOR, which was 4.70% at December 31, 2007.

During 2007, PEF had entered into a combined $225 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, which were terminated on September 13, 2007, in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017.

On July 30, 2007, PEC entered into a $50 million notional forward starting swap and on October 24, 2007, PEC entered into $100 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. On September 25, 2007, PEC amended its 10-year forward starting swap in order to move the maturity date from October 1, 2017, to April 1, 2018.

Marketable Securities Price Risk

The Utilities maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 2008 and 2007, the fair value of these funds was $1.089 billion and $1.384 billion, respectively. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of Florida Progress, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate. The CVOs are derivatives and are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. We perform sensitivity analyses to estimate our exposure to the market risk of the CVOs. The sensitivity analysis performed on the CVOs uses quoted prices obtained from brokers or quote services to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2008 and 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million. A hypothetical 10 percent increase in the December 31, 2008 market price would result in a $3 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

Commodity Price Risk

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

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

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments that are not eligible for recovery from ratepayers. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. At December 31, 2008, substantially all derivative commodity instrument positions were subject to retail regulatory treatment. At December 31, 2007, the only derivative commodity instruments not eligible for recovery from ratepayers related to derivative contracts entered into on January 8, 2007, to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices as discussed below. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings.

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

DISCONTINUED OPERATIONS

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

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate, Ceredo in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R), but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 5). We had a $108 million cash collateral liability related to these contracts at December 31, 2007, included in other current liabilities on the Consolidated Balance Sheet. As discussed in Note 3A, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo, of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

Due to the divestitures of Gas and CCO, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued in 2006. For the year ended December 31, 2006, discontinued operations, net of tax on the Consolidated Statements of

Income included $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges, and immaterial net gains and losses from other derivative instruments related to Gas and CCO.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the 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, 2008 and 2007, PEC recorded a net realized gain of $2 million and a net realized loss of $9 million, respectively. PEC's net realized loss was not material during the year ended December 31, 2006. During the years ended December 31, 2008, 2007 and 2006, PEF recorded a net realized gain of $172 million, a net realized loss of $46 million and a net realized gain of $39 million, respectively.

At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as a $19 million long-term derivative asset position included in derivative assets and a $4 million short-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral with PEC in support of these instruments. PEC had an $18 million cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in prepayments and other current assets, a $1 million long-term derivative asset position included in derivative assets, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as an $83 million short-term derivative asset position included in prepayments and other current assets, a $100 million long-term derivative asset position included in derivative assets, a $38 million short-term derivative liability position included in current derivative liabilities, and a $9 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have posted or held cash collateral in support of these instruments. PEF had a $335 million cash collateral asset included in derivative collateral posted and a $12 million cash collateral liability included in other current liabilities on the Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

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

At December 31, 2008 and 2007, 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, 2008. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2008, Progress Energy maintained effective internal control over financial reporting.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the internal control over financial reporting of Progress Energy as of December 31, 2008, as stated in their report.

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

March 2, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.:

We have audited the internal control over financial reporting of Progress Energy, Inc. (the Company), as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2008, of the Company and our report dated March 2, 2009, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph regarding the adoption of a new accounting principle.

Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2008. 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 the Company at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2, 14 and 16 to the consolidated financial statements, on January 1, 2008 the Company adopted Financial Accounting Standards Board Staff Position No. FIN 39-1, on January 1, 2007 the Company adopted Financial Accounting Standards Board Interpretation No. 48 and on December 31, 2006 the Company adopted Statement of Financial Accounting Standards No. 158.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting at December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 2, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
March 2, 2009

CONSOLIDATED STATEMENTS OF INCOME

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK 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	Total Common Stock Equity
Balance, December 31, 2005, as restated (See Note 1B)	**252**	**$5,571**	**$(63)**	**$(104)**	**$2,607**	**$8,011**
Net income		–	–	–	571	571
Other comprehensive loss		–	–	(18)	–	(18)
Comprehensive income						553
Adjustment to initially apply SFAS No. 158, net of tax		–	–	73	–	73
Issuance of shares	4	70	–	–	–	70
Stock options exercised		115	–	–	–	115
Purchase of restricted stock		(8)	–	–	–	(8)
Allocation of ESOP shares		13	13	–	–	26
Stock-based compensation expense		30	–	–	–	30
Dividends ($2.425 per share)		–	–	–	(611)	(611)
Balance, December 31, 2006, as restated (See Note 1B)	**256**	**5,791**	**(50)**	**(49)**	**2,567**	**8,259**
Net income		–	–	–	504	504
Other comprehensive income		–	–	15	–	15
Comprehensive income						519
Adjustment to initially apply FASB Interpretation No. 48		–	–	–	(2)	(2)
Issuance of shares	4	46	–	–	–	46
Stock options exercised		105	–	–	–	105
Allocation of ESOP shares		15	13	–	–	28
Stock-based compensation expense		71	–	–	–	71
Dividends ($2.445 per share)		–	–	–	(631)	(631)
Balance, December 31, 2007, as restated (See Note 1B)	**260**	**6,028**	**(37)**	**(34)**	**2,438**	**8,395**
Net income		**–**	**–**	**–**	**830**	**830**
Other comprehensive loss		**–**	**–**	**(82)**	**–**	**(82)**
Comprehensive income						**748**
Issuance of shares	**4**	**131**	**–**	**–**	**–**	**131**
Stock options exercised		**1**	**–**	**–**	**–**	**1**
Allocation of ESOP shares		**13**	**12**	**–**	**–**	**25**
Stock-based compensation expense		**33**	**–**	**–**	**–**	**33**
Dividends ($2.465 per share)		**–**	**–**	**–**	**(646)**	**(646)**
Balance, December 31, 2008	**264**	**$6,206**	**$(25)**	**$(116)**	**$2,622**	**$8,687**

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

See Notes to 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 that do not separately meet the quantitative disclosure requirements as a separate 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) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under SFAS No. 95, "Statement of Cash Flows."

These notes accompany and form an integral part of our consolidated financial statements.

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

RESTATEMENT

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

Progress Energy

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

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

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

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

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

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN 46R).

In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk 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 accordance with FIN 46R.

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

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

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2006 through 2008. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2008, PEC had assets of $40 million, substantially all of which was reflected in miscellaneous other property and investment, and $16 million in long-term debt, $7 million in other liabilities and deferred credits and $4 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE 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 $44 million, $39 million and $45 million in 2008, 2007 and 2006, respectively. The generation capacity of the entity's power plant is approximately 847 megawatts (MW). PEC has requested the necessary information to determine if the investment fund's 17 partnerships and the power plant owner are VIEs or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC, and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the power plant and the investment fund consolidating the 17 partnerships would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparties, the impact cannot be determined at this time.

VARIABLE INTEREST ENTITIES FOR WHICH PEF IS NOT THE PRIMARY BENEFICIARY

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

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

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income on the Consolidated Statements of Income were $295 million, $299 million and $293 million for the years ended December 31, 2008, 2007 and 2006, 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 SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R).

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations (AROs) under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), are charged to a regulatory liability.

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 4A).

Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 7).

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

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

ASSET RETIREMENT OBLIGATIONS

We account for AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income. The adoption of SFAS No. 143 and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143" (FIN 47) had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

CASH AND CASH EQUIVALENTS

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

INVENTORY

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

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

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

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

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

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. In accordance with FSP No. FIN 39-1, "An Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts" (FSP FIN 39-1), we elect not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No. 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

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

2. NEW ACCOUNTING STANDARDS

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

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

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

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

Refer to Note 13B for information regarding our first quarter 2008 implementation of SFAS No. 157, "Fair Value Measurements" (SFAS No. 157).

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied on an instrument by instrument basis, is irrevocable (unless a new election date occurs) and is applied to the entire financial instrument. SFAS No. 159 was effective for us on January 1, 2008. We did not elect to adopt the fair value option for any financial instruments.

SFAS No. 141R, "Business Combinations"

In December 2007, the FASB issued SFAS Statement No. 141R, "Business Combinations" (SFAS No. 141R), which introduces significant changes in the accounting for business acquisitions. SFAS No. 141R considerably broadens the definition of a "business" and a "business combination," which will result in an increased number of transactions or other events that will qualify as business combinations. This will affect us primarily in our assessment of VIEs. SFAS No. 141R amends FIN 46R to clarify that the initial consolidation of a business that is a VIE is a business combination in which the acquirer should recognize and measure the fair value of the acquiree as a whole, and the assets acquired and liabilities assumed at their full fair values as of the date control is obtained, regardless of the percentage ownership in the acquiree or how the acquisition was achieved. Other significant changes include the expensing of all acquisition-related transaction costs and most acquisition-related restructuring costs, the fair value remeasurement of certain earn-out arrangements and the discontinuance of the expense at acquisition of acquired-in-process research and development. SFAS No. 141R is effective for us for business combinations for which the acquisition date is on or after January 1, 2009. Earlier application is prohibited. We do not expect the adoption of SFAS No. 141R to have a material impact on our financial position or results of operations.

SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51"

In conjunction with the issuance of SFAS No. 141R, in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" (SFAS No. 160), which introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. SFAS No. 160 also changes the accounting for and reporting for the deconsolidation of a subsidiary. SFAS No. 160 requires that a noncontrolling interest in a consolidated subsidiary be displayed in the consolidated statement of financial position as a separate component of equity rather than as a "mezzanine" item between liabilities and equity. SFAS No. 160 also requires that earnings attributed to the noncontrolling interests be reported as part of consolidated earnings, and requires disclosure of the attribution of consolidated earnings to the controlling and noncontrolling interests on the face of the consolidated income statement. SFAS No. 160 must be adopted concurrently with the effective date of SFAS No. 141R, which for us is January 1, 2009. We do not expect the adoption of SFAS No. 160 to have a material impact on our financial position or results of operations.

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

In March 2008, the FASB issued SFAS Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS No. 161), which requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for us on January 1, 2009, and encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The adoption of SFAS No. 161 will change certain disclosures in the notes to the financial statements, but will have no impact on our financial position or results of operations.

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

In December 2008, the FASB issued FSP No. SFAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets" (FSP SFAS 132R-1), which requires additional disclosures on the investment allocation decision making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. FSP SFAS 132R-1 is effective for us on December 31, 2009. The adoption of FSP SFAS 132R-1 will change certain disclosures in the notes to the financial statements, but will have no impact on our financial position or results of operations.

3. DIVESTITURES

A. Terminals Operations and Synthetic Fuels Businesses

On March 7, 2008, we sold coal terminals and docks in West Virginia and Kentucky (Terminals) for $71 million in gross cash proceeds. The terminals had a total annual capacity in excess of 40 million tons for transloading, blending and storing coal and other commodities. Proceeds from the sale were used for general corporate purposes. During the year ended December 31, 2008, we recorded an after-tax gain of $42 million on the sale of these assets. The accompanying consolidated financial statements reflect the operations of Terminals as discontinued operations.

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

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which was reclassified to discontinued operations, net of tax on the Consolidated Statements of Income. This charge represented the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities were located.

Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2007 and 2006 was $1 million. We ceased recording depreciation upon classification of the assets as discontinued operations in November 2007. After-tax depreciation expense during the years ended December 31, 2007 and 2006 was $2 million and $4 million, respectively.

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

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

B. Coal Mining Businesses

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

On May 1, 2006, we sold certain net assets of three of our coal mining businesses for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets.

The accompanying consolidated financial statements reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for each of the years ended December 31, 2007 and 2006 was $1 million. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

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

C. CCO – Georgia Operations

On March 9, 2007, our subsidiary, Progress Energy Ventures, Inc. (PVI), entered into a series of transactions to sell or assign substantially all of its Competitive Commercial Operations (CCO) physical and commercial assets and liabilities. Assets divested included approximately 1,900 MW of gas-fired generation assets in Georgia. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. We recorded an estimated after-tax loss of $226 million in December 2006. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of the impairment recorded in 2006, respectively.

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

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated for the years ended December 31, 2007 and 2006 was $11 million and $36 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense was $14 million for the year ended December 31, 2006. Results of discontinued operations for CCO for the years ended December 31 were as follows:

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

D. Natural Gas Drilling and Production

On October 2, 2006, we sold our natural gas drilling and production business (Gas) for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd., Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels). Proceeds from the sale were used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006. We recorded an after-tax loss of $2 million during the year ended December 31, 2007, primarily related to working capital adjustments.

The accompanying consolidated financial statements reflect the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $13 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense was $16 million for the year ended December 31, 2006. Results of discontinued operations for Gas for the years ended December 31 were as follows:

(in millions)	2007	2006
Revenues	$–	$192
Earnings before income taxes	$–	$135
Income tax benefit (expense)	4	(53)
Net earnings from discontinued operations	4	82
(Loss) gain on disposal of discontinued operations, including income tax benefit (expense) of $1 and $(188), respectively	(2)	300
Earnings from discontinued operations	$2	$382

E. CCO – DeSoto and Rowan Generation Facilities

On May 8, 2006, we entered into definitive agreements to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan), including certain existing power supply contracts to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. DeSoto owned a 320-MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owned a 925-MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. We used the proceeds from the sales to reduce debt and for other corporate purposes.

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Pre-tax interest expense allocated was $6 million for the year ended December 31, 2006. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the year ended December 31, 2006, was $3 million. Results of discontinued operations for DeSoto and Rowan for the year ended December 31 were as follows:

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

F. Progress Telecom, LLC

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

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax net gain on disposal of $28 million during the year ended December 31, 2006.

The accompanying consolidated financial statements reflect the operations of PT LLC as discontinued operations. Results of discontinued operations for PT LLC for the year ended December 31 were as follows:

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

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3 Communications, Inc. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

G. Dixie Fuels and Other Fuels Business

On March 1, 2006, we sold Progress Fuels' 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units. Dixie Fuels primarily transported coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels during the year ended December 31, 2006. During the years ended December 31, 2008 and 2007, we recorded additional gains of $1 million and $2 million, respectively, primarily related to the expiration of indemnifications.

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

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

H. Progress Rail

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

I. Net Assets to be Divested

At December 31, 2007, the assets and liabilities of Terminals and the remaining assets and liabilities of Coal Mining were included in net assets to be divested. The major balance sheet classes included in assets and liabilities to be divested in the Consolidated Balance Sheets were as follows:

(in millions)	December 31, 2007
Inventory	$6
Other current assets	2
Property, plant and equipment, net	38
Other assets	6
Assets to be divested	$52
Accrued expenses	$3
Long-term liabilities	5
Liabilities to be divested	$8

J. Ceredo Synthetic Fuels Interests

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

During the year ended December 31, 2008, we recognized previously deferred gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A. In connection with the disposal, Progress Fuels and Progress Energy provided guarantees and indemnifications for certain legal and tax matters to the buyer. The ultimate resolution of these matters could result in adjustments to the loss on disposal in future periods. See general discussion of guarantees at Note 22C.

On the date of the transaction, the carrying value of the disposed ownership interest totaled $37 million, which consisted primarily of the fair value of crude oil call options purchased in January 2007. Subsequent to the disposal, we remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with FIN 46R, but record a 100 percent minority interest.

K. Synthetic Fuels Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales were received over time, which is typical of such sales in the industry. Gains from the sales were recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized a gain on these transactions of $4 million in the year ended December 31, 2006. In 2007, due to the increase in the price of oil that limits synthetic fuels tax credits, we did not record any additional gains. The operations of Colona are reflected in discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

4. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	Depreciable Lives	2008	2007
Production plant	7-43	**$14,117**	$13,765
Transmission plant	17-75	**2,970**	2,684
Distribution plant	13-55	**8,028**	7,676
General plant and other	5-35	**1,211**	1,202
Utility plant in service		**$26,326**	$25,327

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

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

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

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

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $145 million, $139 million and $140 million for the years ended December 31, 2008, 2007 and 2006, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income. Amortization of nuclear fuel costs for the years ended December 31, 2008, 2007 and 2006 was $115 million, $110 million and $109 million, respectively, for PEC and $30 million, $29 million and $31 million, respectively, for PEF.

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

B. Diversified Business Property

Net diversified business property is included in miscellaneous other property and investments on our and PEC's Consolidated Balance Sheets. Diversified business property excludes amounts reclassified as assets to be divested (See Note 3I).

The balances of diversified business property at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	**2008**	2007
Equipment (3-25 years)	**S5**	S6
Buildings (5-40 years)	**9**	9
Accumulated depreciation	**(8)**	(9)
Diversified business property, net	**S6**	S6

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

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the above jointly owned generating facilities is included within the corresponding line in the 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 appear in the following table with related information at December 31:

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

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

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

D. Asset Retirement Obligations

At December 31, 2008 and 2007, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $163 million and $150 million, respectively. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.089 billion and $1.384 billion at December 31, 2008 and 2007, respectively. Net nuclear decommissioning trust 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 2008, 2007 and 2006. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 AROs, which are included in depreciation, amortization and accretion expense, were $133 million, $126 million and $123 million in 2008, 2007 and 2006, respectively.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006. In 2009, PEF will be required to file an updated depreciation study.

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

(in millions)	2008	2007
Removal costs	$1,478	$1,410
Nonirradiated decommissioning costs	146	141
Dismantlement costs	124	125
Non-ARO cost of removal	$1,748	$1,676

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick

Unit No. 2 and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. NRC operating licenses held by PEC currently expire in July 2030, December 2034, September 2036 and October 2046 for Robinson, Brunswick Units No. 2 and No. 1 and Harris, respectively. On December 17, 2008, Harris received a 20-year extension from the NRC on its operating license, which extends the operating license through 2046. Based on updated assumptions, in 2005 PEC further reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively. In 2009, PEC will be required to file an updated nuclear decommissioning study.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for Crystal River Unit No. 3 (CR3) in October 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing (See Note 7C). PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF submitted an application requesting a 20-year extension of this license on December 18, 2008. PEF expects a decision from the NRC in 2011. As part of this new estimate and assumed license extension, PEF increased its asset retirement cost and its ARO liability by approximately $19 million. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. PEF expects to continue this suspension based on its planned 2009 base rate filing. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF will file with the FPSC in 2009 as part of PEF's planned base rate filing. PEF's reserve for fossil plant dismantlement was approximately $145 million and $144 million at December 31, 2008 and 2007, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants.

The Utilities have recognized ARO liabilities related to asbestos abatement costs (See Note 1D). In 2008, we reduced the ARO liabilities related to asbestos abatement costs for the fossil plants by $12 million due to an updated study. An additional ARO liability of $7 million was recognized in 2008 for landfill capping costs.

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

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

(in millions)	Regulated	Nonregulated
Asset retirement obligations at January 1, 2007	$1,303	$1
Accretion expense	75	–
Remediation	–	(1)
Asset retirement obligations at December 31, 2007	1,378	–
Additions	**7**	–
Accretion expense	**79**	–
Revisions to prior estimates	**7**	–
Asset retirement obligations at December 31, 2008	**$1,471**	**$–**

E. Insurance

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

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $37 million with respect to the primary coverage, $38 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $12.520 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

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

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

5. RECEIVABLES

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

(in millions)	**2008**	2007
Trade accounts receivable	**$648**	$616
Unbilled accounts receivable	**182**	175
Notes receivable	**2**	67
Derivatives accounts receivable	–	247
Other receivables	**53**	46
Allowance for doubtful receivables	**(18)**	(29)
Total receivables, net	**$867**	$1,122

6. INVENTORY

At December 31 inventory was comprised of:

(in millions)	**2008**	2007
Fuel for production	**$614**	$455
Materials and supplies	**588**	520
Emission allowances	**37**	19
Total inventory	**$1,239**	$994

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 $23 million and $65 million at December 31, 2008 and 2007, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets of $61 million and $32 million at December 31, 2008 and 2007, respectively.

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

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of SFAS No. 71. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of SFAS No. 71 could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We anticipate recovering long-term deferred fuel costs beginning in 2010 and loss on reacquired debt over the applicable lives of the debt. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

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

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

B. PEC Retail Rate Matters

BASE RATES

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

On March 23, 2007, PEC filed a petition with the NCUC requesting that it be allowed to amortize the remaining 30 percent (or $244 million) of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, with discretion to amortize up to $174 million in either year. Additionally, among other things, PEC requested in its March 23, 2007 petition that the NCUC allow PEC to include in its rate base those eligible compliance costs exceeding the original estimated compliance costs and that PEC be allowed to accrue AFUDC on all eligible compliance costs in excess of the original estimated compliance costs. PEC also requested that any prudency review of PEC's environmental compliance costs be deferred until PEC's next ratemaking proceeding in which PEC seeks to adjust its base rates. On October 22, 2007, PEC filed with the NCUC a settlement agreement with the NCUC Public Staff, the Carolina Utility Customers Association (CUCA) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) supporting PEC's proposal. On December 20, 2007, the NCUC approved the settlement agreement on a provisional basis, with the NCUC indicating that it intended to initiate a review in 2009 to consider all reasonable alternatives and proposals related to PEC's recovery of its Clean Smokestacks Act compliance costs in excess of the original estimated compliance costs of $813 million.

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

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

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

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

FUEL COST RECOVERY

On April 30, 2008, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers. PEC asked the SCPSC to approve a $39 million increase in fuel rates for under-recovered fuel costs associated with prior year settlements and to meet future expected fuel costs. On June 26, 2008, the SCPSC approved PEC's request. Effective July 1, 2008, residential electric bills increased by $5.86 per 1,000 kilowatt-hours (kWh), or 6.1 percent, for fuel cost recovery. At December 31, 2008, PEC's South Carolina under-recovered deferred fuel balance was $15 million.

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

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

During 2007, the North Carolina legislature passed comprehensive energy legislation, which became law on August 20, 2007. Among other provisions, the law allows the utility to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs intended to produce future benefits and authorizes the NCUC to approve other forms of financial incentives to the utility for DSM and energy-efficiency programs. DSM programs include, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. PEC has begun implementing a series of DSM and energy-efficiency programs and, as of December 31, 2008, has deferred $8 million of implementation and program costs for future recovery. In 2008, PEC filed for NCUC approval of multiple DSM and energy-efficiency programs. The majority of the programs has been approved by the NCUC or is pending further review. We cannot predict the outcome of the DSM and energy-efficiency filings pending further approval by the NCUC or whether the programs will produce the expected operational and economic results.

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

PEC filed a petition on November 30, 2007, with the SCPSC seeking authorization to create a deferred account for DSM and energy-efficiency expenses. On December 21, 2007, the SCPSC issued an order granting PEC's petition. As a result, PEC has deferred $1 million of implementation and program costs for future recovery in the South Carolina jurisdiction. On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. A hearing on this matter was held on February 12, 2009. We cannot predict the outcome of this matter.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's comprehensive energy legislation. These rules provide filing requirements associated with the legislation. The order required PEC to submit its first annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance plan as part of its integrated resource plan, which was filed on September 2, 2008. Under the new rules, beginning in 2009, PEC will also be required to file an annual NC REPS compliance report demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC will pursue a third-party REC tracking system, but will not develop or require participation in a REC trading platform at this time. Rates for the NC REPS clause will be set based on projected costs with true-up provisions. On June 6, 2008, and as amended on August 22, 2008, PEC filed an application with the NCUC for approval of a NC REPS clause to recover the costs of this program. On November 14, 2008, the NCUC approved a monthly charge per customer rather than a usage-based rate. Effective December 1, 2008, residential electric bills increased $0.36 per month.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery are $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $415 million for the North Carolina jurisdiction. The South Carolina aggregate minimum and maximum amounts of cost recovery are $115 million and $165 million, respectively. No additional depreciation expense from accelerated cost recovery was recorded in 2008, 2007 or 2006. Through December 31, 2008, PEC recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction.

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

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

On April 30, 2008, PEC submitted a revised Open Access Transmission Tariff (OATT) filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent as well as recovery of the wholesale portion of the terminated GridSouth Transco, LLC (GridSouth) project startup costs over five years. On June 27, 2008, the FERC approved the settlement. The new rates were effective July 1, 2008, and increased 2008 revenues by $7 million.

C. PEF Retail Rate Matters

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010 pursuant to the agreement. In accordance with the base rate agreement and as modified by a stipulation and settlement agreement approved by the FPSC on October 23, 2007, base rates were adjusted in January 2008 due to specified generation facilities placed in service in 2007. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006, whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified thresholds in 2008, 2007 or 2006 and thus no revenues were subject to revenue sharing. Both the base threshold and the cap will be adjusted annually for rolling average 10-year retail kWh sales growth and were $1.664 billion and $1.716 billion, respectively, for 2008. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and cost-recovery clause return calculations. PEF will use an authorized 11.75 percent return on equity for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory return on equity falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

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

As part of its February 12, 2009 notification, PEF also informed the FPSC that it may seek additional rate relief in 2009, primarily driven by the addition of its repowered

Bartow power plant, which is expected to begin commercial operation in June 2009, and decreased sales and higher pension costs impacted by the current financial and credit crises. We cannot predict the outcome of this matter.

FUEL COST RECOVERY

On September 4, 2007, PEF filed a request with the FPSC seeking approval of a cost adjustment to reflect a projected over-collection of fuel costs in 2007, declining projected fuel costs for 2008 and other recovery clause factors. On January 8, 2008, the FPSC issued an order approving PEF's request for a $163 million, or 4.53 percent, decrease in rates effective January 1, 2008.

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

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

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

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and SO_2 allowance costs during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claimed that although Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC found that PEF had not been prudent in purchasing a portion of its coal requirements during the period from 2003 to 2005. Accordingly, the FPSC ordered PEF to refund its ratepayers approximately $14 million, inclusive of interest, over a 12-month period beginning January 1, 2008. For the year ended December 31, 2007, PEF recorded a pre-tax other operating expense of $12 million, interest expense of $2 million and an associated $14 million regulatory liability included within PEF's deferred fuel cost at December 31, 2007. The refund was returned to ratepayers through a reduction of prior year under-recovered fuel costs. The FPSC also ordered

PEF to address whether it was prudent in its 2006 and 2007 coal purchases for CR4 and CR5. On October 4, 2007, PEF filed a motion to establish a separate docket on the prudence of its coal purchases for CR4 and CR5 for the years 2006 and 2007. On October 17, 2007, the FPSC granted that motion. PEF believes its coal procurement practices have been prudent. A hearing on PEF's 2006 and 2007 coal purchases has been scheduled for April 13-15, 2009. On February 2, 2009, the OPC filed direct testimony in this hearing alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 plants. We cannot predict the outcome of this matter.

NUCLEAR COST RECOVERY

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

CR3 Uprate

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

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

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

Levy Nuclear

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

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

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

STORM COST RECOVERY

In 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007 and 2006, PEF recorded amortization of $75 million and $122 million, respectively, associated with the recovery of these storm costs. The retail portion of storm restoration costs were fully recovered at December 31, 2007.

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its then-current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which began August 2007, was expected to replenish the existing storm reserve by an estimated $126 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. At December 31, 2008, PEF's storm reserve totaled $129 million.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the PEF OATT in order to more accurately reflect the costs that PEF incurs in providing transmission service. In the filing, PEF proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. Settlement discussions were held with major customers prior to the filing and a settlement agreement was reached on all issues. The settlement proposed a formula rate with a rate of return on equity of 10.8 percent. PEF received FERC approval of the settlement agreement on December 17, 2007. The new rates were effective January 1, 2008, and increased 2008 revenues by $2 million.

D. Regional Transmission Organizations

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (RTOs) must meet, including independent transmission service. In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO. PEC participated in the mediation; no consensus was reached on creating a southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding.

On November 16, 2007, PEC petitioned the NCUC to allow it to establish a regulatory asset for PEC's development costs of GridSouth pending disposition in a general rate proceeding. On January 14, 2008, the NCUC issued an order requesting interested parties to file comments regarding PEC's petition on or before January 28, 2008. On February 11, 2008, PEC filed response comments. On December 20, 2007, the NCUC issued an order for one of the other GridSouth partners. As part of that order, the NCUC ruled that the utility's GridSouth development costs should be amortized and recovered over a 10-year period beginning June 2002. Consequently, in 2007, PEC recorded an $11 million charge to amortization expense. On June 4, 2008, the NCUC issued an order granting PEC the same accounting treatment to its GridSouth development costs. In accordance with the OATT settlement discussed above, in July 2008, PEC began amortization and recovery of the wholesale portion of PEC's GridSouth development costs over a five-year period. The impact of this wholesale amortization was $1 million in 2008 and is estimated to be $2 million annually during the remaining amortization period. PEC's recorded investment in GridSouth totaled $19 million and $22 million at December 31, 2008 and 2007, respectively.

E. Nuclear License Renewals

The NRC operating license for Robinson expires in 2030 and the licenses for Brunswick expire in 2036 for Unit No. 1 and 2034 for Unit No. 2. On December 17, 2008, the NRC issued a 20-year extension on the operating license for Harris, which extends the operating license through 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year extension from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL AND INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2008 and 2007; each test indicated no impairment.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. At December 31, 2008 and 2007, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. There were no changes to the assignment of the carrying amounts to PEC and PEF in 2008 or 2007.

Goodwill was previously allocated to our former CCO-Georgia Operations reporting unit, which was comprised of four nonregulated generating plants. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Operations, we performed an interim goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income (See Note 3C).

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 3A). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current idled state of our synthetic fuels facilities. We estimated the fair value using the expected present value of future cash flows. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which has been reclassified to discontinued operations, net of tax on the Consolidated Statements of Income.

9. EQUITY

A. Common Stock

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

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

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

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2008 and 2007, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 1.1 million and 1.7 million ESOP suspense shares at December 31, 2008 and 2007, respectively, with a fair value of $45 million and $82 million, respectively. ESOP shares allocated to plan participants totaled 12.6 million and 10.6 million at December 31, 2008 and 2007, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $8 million, $23 million and $14 million for the years ended December 31, 2008, 2007 and 2006, respectively. Total matching and incentive costs were approximately $34 million, $30 million and $23 million for the years ended December 31, 2008, 2007 and 2006, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

Effective January 1, 2008, the 401(k) Plan was revised. As revised, the employer match percentage was increased and the employee stock incentive plan based on goal attainment was discontinued.

STOCK OPTIONS

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

A summary of the status of our stock options at December 31, 2008, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	1.7	$43.99
Canceled	–	44.38
Exercised	(0.1)	43.83
Options outstanding, December 31	1.6	43.99
Options exercisable, December 31	1.6	43.99

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

Compensation cost, for expense purposes subsequent to the adoption of SFAS No. 123R, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the grant date using a Black-Scholes option pricing model. Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

At December 31, 2006, all options were fully vested; therefore, no compensation expense was recognized in 2008 or 2007. Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

Cash received from the exercise of stock options totaled $1 million, $105 million and $115 million, respectively, during the years ended December 31, 2008, 2007 and 2006. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2007 and 2006, was $6 million and $4 million, respectively. The actual tax benefit deduction for stock option exercises for the year ended December 31, 2008, was not significant.

OTHER STOCK-BASED COMPENSATION PLANS

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

We granted cash-settled PSSP awards prior to 2005. Since 2005, we have been granting stock-settled PSSP awards. Under the terms of the PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, additional performance shares. Prior to 2007, shares issued under the PSSP (both cash-settled and stock-settled) had two equally weighted performance measures, both based on our results as compared to a peer group of utilities. In 2007, the PSSP was redesigned, and shares issued under the revised plan use one performance measure. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. For cash-settled awards, compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated to reflect factors such as changes in stock price and the status of performance measures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities totaling $2 million, $3 million and $4 million were paid in the years ended December 31, 2008, 2007 and 2006, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2008, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares[a]	Weighted-Average Grant Date Fair Value
Beginning balance	1,629,995	$44.97
Granted	271,964	42.41
Vested	(441,435)	44.23
Paid[b]	(228,793)	50.70
Forfeited	(113,127)	44.76
Ending balance	1,118,604	46.46

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

[b] Shares paid include only target shares as originally granted. Additional shares of 131,881 were issued and paid due to exceeding established performance thresholds and due to dividends earned.

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

The Restricted Stock Award program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2008, and changes during the year then ended, is presented below:

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

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

The total fair value of restricted stock awards vested during the years ended December 31, 2008, 2007 and 2006 was $3 million, $13 million and $4 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million during the year ended December 31, 2006. Cash expended to purchase shares for 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program and the rollout of the new restricted stock unit (RSU) program.

Beginning in 2007, we began issuing RSUs rather than restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are not included as shares outstanding in the basic earnings per share calculation until shares are no longer forfeitable. Units are converted to shares upon vesting. A summary of the status of nonvested RSUs at December 31, 2008, and changes during the year then ended, follows:

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

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

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

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

C. Earnings per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effects of the nonvested portion of restricted stock, restricted stock unit awards and performance share awards and the effect of stock options outstanding.

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

(in millions)	**2008**	2007	2006
Weighted-average common shares – basic	**260.3**	256.1	250.4
Net effect of dilutive stock-based compensation plans	**0.5**	0.6	0.4
Weighted-average shares – fully diluted	**260.8**	256.7	250.8

There were no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average ESOP shares totaled 1.2 million, 1.8 million and 2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. There were 1.6 million, 0.1 million and 1.8 million stock options outstanding at December 31, 2008, 2007 and 2006, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

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

(in millions)	**2008**	2007
Loss on cash flow hedges	**$(57)**	$(23)
Pension and other postretirement benefits	**(58)**	(13)
Other	**(1)**	2
Total accumulated other comprehensive loss	**$(116)**	$(34)

10. PREFERRED STOCK OF SUBSIDIARIES – NOT SUBJECT TO MANDATORY REDEMPTION

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2008 and 2007, preferred stock outstanding consisted of the following:

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

11. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2008):

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

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

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings. On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

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

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

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

At December 31, 2008 and 2007, we had committed lines of credit used to support our commercial paper borrowings. As a result of financial and economic conditions in 2008, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets, which is reflected in the outstanding borrowings under our credit facilities as shown in the table below. As discussed above, of the $600 million outstanding, $100 million was classified as long-term debt at December 31, 2008. We will continue to monitor the commercial paper and short-term credit markets to determine when to repay the outstanding balance of the RCA loan, while maintaining an appropriate level of liquidity. At December 31, 2007, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our RCAs and available capacity at December 31, 2008:

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

[a] In February 2009, the Parent repaid $100 million of its outstanding RCA borrowings.
[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2008, the Parent had $30 million of letters of credit issued, which were supported by the RCA.

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

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

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

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

(in millions)	
2009	$–
2010	406
2011	1,000
2012	1,050
2013	825
Thereafter	7,435
Total	$10,716

B. Covenants and Default Provisions

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2008, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	57.8%
PEC	65%	45.5%
PEF	65%	58.6%

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

CROSS-DEFAULT PROVISIONS

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

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

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2008, the Parent had no shares of preferred stock outstanding.

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

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2008, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2008, PEC's common stock equity was approximately 54.7 percent of total capitalization. At December 31, 2008, none of PEC's cash dividends or distributions on common stock was restricted.

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2008, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2008, PEF's common stock equity was approximately 44.6 percent of total capitalization. At December 31, 2008, none of PEF's cash dividends or distributions on common stock was restricted.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2008, PEC and PEF had a total of $2.994 billion and $4.041 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

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

E. Hedging Activities

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

12. INVESTMENTS

A. Investments

At December 31, 2008 and 2007, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

(in millions)	2008	2007
Nuclear decommissioning trust (See Note 4D)	**$1,089**	$1,384
Equity method investments[a]	**22**	23
Cost investment[b]	**7**	8
Company-owned life insurance[c]	**49**	51
Benefit investment trusts[d]	**184**	199
Marketable debt securities	**1**	1
Total	**$1,352**	$1,666

[a] Investments in unconsolidated companies are included in miscellaneous other property and investments in the Consolidated Balance Sheets using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20).
[b] Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
[c] Investments in company-owned life insurance are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the nature of the investment.
[d] Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets and are principally at fair value. At December 2008 and 2007, $142 million and $155 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's benefit investment trusts are invested in company-owned life insurance.

B. Impairment of Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information. There were no material other-than-temporary impairments in 2008, 2007 or 2006.

13. FAIR VALUE DISCLOSURES

A. Debt and Investments

DEBT

The carrying amount of our long-term debt, including current maturities, was $10.659 billion and $9.614 billion at December 31, 2008 and 2007, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11.260 billion and $9.897 billion at December 31, 2008 and 2007, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 4D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at fair value. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value. Our available-for-sale securities at December 31, 2008 and 2007 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

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

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

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Under GAAP, such securities are considered to be impaired if they are in a loss position. Due to the ratemaking treatment with regard to nuclear decommissioning (See Note 12B), gains and losses on the nuclear decommissioning trusts accrue to the benefit or detriment of ratepayers and are included in the determination of regulatory assets and liabilities (See Note 7A), with no earnings impact. Therefore, the tables above include the book value and unrealized gains and losses for the nuclear decommissioning trusts based on the original cost of the trust investments; $118 million of the unrealized losses and $148 million of the unrealized gains for 2008 and all unrealized losses and gains for 2007 relate to the decommissioning trusts. The aggregate fair values of investments that related to the 2008 and 2007 unrealized losses were $374 million and $243 million, respectively.

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

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

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

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

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities (See Note 12A). For the years ended December 31, 2007 and 2006, our proceeds from the sale of these securities were $399 million and $1.7 billion, respectively. For the year ended December 31, 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2008, 2007 and 2006 for investments in these benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2008 and 2007, our other securities had no investments in a continuous loss position for greater than 12 months.

B. Fair Value Measurements

In September 2006, the FASB issued SFAS No.157, which defines fair value, establishes a framework for measuring fair value under GAAP, and requires enhanced disclosures about assets and liabilities carried at fair value. SFAS No. 157 also establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. In February 2008, the FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which delayed for us the effective date of SFAS No. 157 until January 1, 2009, for all nonfinancial assets and nonfinancial liabilities, except for those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

We implemented SFAS No. 157 as of January 1, 2008, for all recurring financial assets and liabilities. The adoption of SFAS No. 157 for recurring financial assets and liabilities did not have a material impact on our financial position or results of operations. We utilized the deferral provision of FSP No. FAS 157-2 for all nonrecurring nonfinancial assets and liabilities within its scope. Major categories of our assets and liabilities to which the deferral applies include reporting units and long-lived asset groups measured at fair value for impairment purposes, AROs initially recognized at fair value, and nonfinancial liabilities for exit and disposal costs and indemnifications initially measured at fair value. The January 1, 2009, adoption of SFAS No. 157 for nonrecurring nonfinancial assets and liabilities did not have a material impact on our financial position or results of operations.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient and requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. SFAS No. 157 requires that valuation techniques maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

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

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

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

The following tables set forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS No. 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$–	$10	$–	$10
Nuclear decommissioning trust funds	592	497	–	1,089
Other marketable securities	16	38	–	54
Total assets	$608	$545	$–	$1,153
Liabilities				
Commodity derivatives	$–	$(647)	$(41)	$(688)
Interest rate derivatives	–	(65)	–	(65)
CVO derivatives	–	(34)	–	(34)
Total liabilities	$–	$(746)	$(41)	$(787)

The determination of the fair values above incorporates various factors required under SFAS No. 157, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our credit risk on our liabilities.

Commodity 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.

Nuclear decommissioning trust funds reflect the assets of the Utilities' nuclear decommissioning trusts, as discussed in Note 12A. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2.

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

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

The following tables set forth a reconciliation of changes in the fair value of our commodity derivatives classified as Level 3 in the fair value hierarchy for the 12 months ended December 31, 2008.

(in millions)	
Derivatives, net at January 1, 2008	$26
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(102)
Purchases, issuances and settlements, net	–
Transfers out of Level 3, net	35
Derivatives, net at December 31, 2008	$(41)

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

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

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

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

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

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

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

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

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

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

- We increased our valuation allowances by $12 million during 2008. Additional valuation allowances of $9 million were recorded related to PVI's 2007 state net operating loss carry forward. Additional valuation allowances of $3 million were recorded to fully offset state net operating loss and state capital loss carry forwards generated during 2008.
- We reduced our valuation allowances and deferred income tax assets by $36 million during 2008 due to the ceasing of business operations in various state taxing jurisdictions. The $36 million of valuation allowances were previously recorded to fully offset $36 million of state deferred income tax assets related to our terminal, coal mining and synthetic fuel businesses. During 2008, we sold our terminal and remaining coal mining businesses and dissolved our synthetic fuel businesses, which caused us to cease business operations in various state taxing jurisdictions. We believe that we will not realize the deferred income tax assets for those jurisdictions, and accordingly we reduced our total deferred income tax assets and corresponding valuation allowances by $36 million, which had no net impact on total deferred income tax assets.

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

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

	2008	2007	2006
Effective income tax rate	**33.7%**	32.3%	37.5%
State income taxes, net of federal benefit	**(3.8)**	(2.8)	(3.5)
Investment tax credit amortization	**1.0**	1.1	1.3
Employee stock ownership plan dividends	**1.0**	1.1	1.3
Domestic manufacturing deduction	**0.3**	1.0	0.4
AFUDC equity	**2.5**	0.7	(0.1)
Other differences, net	**0.3**	1.6	(1.9)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2008**	2007	2006
Current – federal	**$38**	$285	$394
– state	**12**	36	70
Deferred – federal	**305**	13	(94)
– state	**49**	11	(17)
Investment tax credit	**(12)**	(12)	(12)
State net operating loss carry forward	**(6)**	1	(2)
Beginning-of-the-year valuation allowance change	**9**	–	–
Total income tax expense	**$395**	$334	$339

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

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

- Taxes related to discontinued operations recorded net of tax for 2008, 2007 and 2006, which are presented separately in Notes 3A through 3G.
- Taxes related to other comprehensive income recorded net of tax for 2008, 2007 and 2006, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $6 million, which was recorded in common stock during 2007, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. Current tax benefit of $3 million, which was recorded in common stock during 2006, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2008.
- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48) on January 1, 2007

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

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

We file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. During 2007, we closed federal tax years 1998 to 2003. Our open federal tax years are from 2004 forward and our open state tax years in our major jurisdictions are generally from 2003 forward. The Internal Revenue Service (IRS) is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when those examinations will be completed. We are not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2009.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2008 and 2007, the net interest expense related to unrecognized tax benefits was $4 million and $1 million, respectively, of which a respective $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. During 2007, there were no penalties related to unrecognized tax benefits. At December 31, 2008 and 2007, we had accrued $27 million and $23 million, respectively, for interest and penalties, which are included in other liabilities and deferred credits on the Consolidated Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

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

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuel facilities (See Note 3J). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. During 2007, a $5 million deposit was made into a CVO trust for the net after-tax cash flows generated by the four Earthco synthetic fuels facilities in 2004. Deposits into the trust will be classified as a restricted cash asset until the applicable tax years are closed, at which time a payment will be disbursed to the CVO holders. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2008 and 2007 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheet at December 31, 2008.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

The components of the net periodic benefit cost for the years ended December 31 were:

We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158), as of December 31, 2006. SFAS No. 158 amended prior accounting requirements for pension and OPEB plans. Prior to the implementation of SFAS No. 158, other comprehensive income (OCI) reflected minimum pension adjustments related to our pension plans. Our pre-tax minimum pension adjustment recognized as a component of OCI was a net actuarial gain of $78 million for the year ended December 31, 2006. No amounts related to our OPEB plans were recognized as a component of OCI for the year ended December 31, 2006. The table below provides a summary of amounts recognized in other comprehensive income for 2008 and 2007 and other comprehensive income reclassification adjustments for amounts included in net income for 2008 and 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF.

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

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

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

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

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**6.20%**	5.95%	5.65%	**6.20%**	5.95%	5.65%
Rate of increase in future compensation						
Bargaining	**4.25%**	4.25%	3.50%	–	–	–
Supplementary plans	**5.25%**	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.00%	**8.10%**	7.70%	8.30%

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plan assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. We used an expected long-term rate of 9.0%, the low end of the range, for 2008, 2007 and 2006.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

SFAS No. 158 requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the benefit obligations and the funded status as of December 31, 2008 and 2007 are presented in the table below, with each table followed by related supplementary information.

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

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

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

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

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

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

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

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

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

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

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	**2008**	2007
Discount rate	**6.30%**	6.20%	**6.20%**	6.20%
Rate of increase in future compensation				
Bargaining	**4.25%**	4.25%	–	–
Supplementary plans	**5.25%**	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	**9.00%**	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	**9.00%**	9.00%
Ultimate medical cost trend rate	–	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	–	–	**2016**	2015

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

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

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

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

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our employer contributions for 2008 and 2007 include contributions directly to pension plan assets of $33 million and $63 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 for Progress Energy. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2008 and 2007, the subsidies totaled $3 million.

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

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

The asset allocation for the benefit plans at the end of 2008 and 2007 and the target allocation for the plans, by asset category, are presented in the following tables.

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

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

For pension plan assets and a substantial portion of OPEB plan assets, we set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2009, we expect to make at least $130 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $154, $157, $158, $167, $169 and $923, respectively. The expected benefit payments for the OPEB plan for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $40, $43, $45, $48, $50 and $268, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2009 through 2013 and in total for 2014 through 2018, in millions, are approximately $4, $4, $5, $5, $6 and $40, respectively.

B. Florida Progress Acquisition

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

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

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

As discussed in Note 15, in connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. The CVOs are derivatives and are recorded at fair value. The unrealized loss/gain recognized due to changes in fair value is recorded in other, net on the Consolidated Statements of Income (See Note 20). At December 31, 2008 and 2007, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $34 million.

A. Commodity Derivatives

GENERAL

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

In 2003, we recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2008 and 2007, the remaining liability was $7 million and $10 million, respectively.

DISCONTINUED OPERATIONS

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

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange basis. The notional quantity of these oil price hedge instruments was 25 million barrels and provided protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts were marked-to-market with changes in fair value recorded through earnings. These contracts ended on December 31, 2007, and were settled for cash on January 8, 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo. As discussed in Note 3J, we disposed of our 100 percent ownership interest in Ceredo on March 30, 2007. Progress Energy is the primary beneficiary of, and continues to consolidate Ceredo in accordance with FIN 46R, but we have recorded a 100 percent minority interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. At December 31, 2007, the fair value of all of these contracts was recorded as a $234 million short-term derivative asset position, including $79 million at Ceredo. The fair value of these contracts was included in receivables, net on the Consolidated Balance Sheet (See Note 5). We had a $108 million cash collateral liability related to these contracts at December 31, 2007, included in other current liabilities on the Consolidated Balance Sheet. As discussed in Note 3A, on October 12, 2007, we permanently ceased production of synthetic fuels at our majority-owned facilities. Because we have abandoned our majority-owned facilities and our other synthetic fuels operations ceased as of December 31, 2007, gains and losses on these contracts were included in discontinued operations, net of tax on the Consolidated Statement of Income in 2007. During the year ended December 31, 2007, we recorded net pre-tax gains of $168 million related to these contracts. Of this amount, $57 million was attributable to Ceredo, of which $42 million was attributed to minority interest for the portion of the gain subsequent to the disposal of Ceredo.

Due to the divestitures of Gas and CCO, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts would be fulfilled and cash flow hedge accounting for the contracts was discontinued in 2006. For the year ended December 31, 2006, discontinued operations, net of tax on the Consolidated Statements of Income included $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges, and immaterial net gains and losses from other derivative instruments related to Gas and CCO.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the 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. During the years ended December 31, 2008 and 2007, PEC recorded a net realized gain of $2 million and a net realized loss of $9 million, respectively. PEC's net realized loss was not material during the year ended December 31, 2006. During the years ended December 31, 2008, 2007 and 2006, PEF recorded a net realized gain of $172 million, a net realized loss of $46 million and a net realized gain of $39 million, respectively.

At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as a $19 million long-term derivative asset position included in derivative assets and a $4 million short-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral with PEC in support of these instruments. PEC had an $18 million cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in prepayments and other current assets, a $1 million long-term derivative asset position included in derivative assets, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2007, the fair value of such instruments was recorded as an $83 million short-term derivative asset position included in prepayments and other current assets, a $100 million long-term derivative asset position included in derivative assets, a $38 million short-term derivative liability position included in current derivative liabilities, and a $9 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have posted or held cash collateral in support of these instruments. PEF had a $335 million cash collateral asset included in derivative collateral posted and a $12 million cash collateral liability included in other current liabilities on the Consolidated Balance Sheet at December 31, 2008, and no cash collateral position at December 31, 2007.

CASH FLOW HEDGES

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

At December 31, 2008 and 2007, 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. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

The fair values of open interest rate cash flow hedges at December 31 were as follows:

(in millions)	**2008**	2007
Fair value of liabilities	**$(65)**	$(12)

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

The following table presents selected information related to interest rate cash flow hedges included in accumulated other comprehensive income at December 31, 2008:

(term in years/millions of dollars)	
Maximum term	Less than 1
Accumulated other comprehensive loss, net of tax[a]	$(56)
Portion expected to be reclassified to earnings during the next 12 months[b]	$(3)

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

At December 31, 2007, including amounts related to terminated hedges, we had $24 million of after-tax deferred losses, including $12 million of after-tax deferred losses at PEC and $8 million of after-tax deferred losses at PEF, recorded in accumulated other comprehensive income related to interest rate cash flow hedges.

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

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

At December 31, 2008 and 2007, PEF had no outstanding interest rate cash flow hedge positions. During 2008, PEF entered into a combined $550 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances. In June 2008, all of PEF's forward starting swaps were terminated in conjunction with PEF's issuance of $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. In January 2009, PEF entered into a $50 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2008 and 2007, we did not have any outstanding positions in such contracts.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2008, the Parent had issued $386 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

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

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2008, 2007 and 2006 to PEC amounted to $194 million, $182 million and $188 million, respectively, and services provided to PEF were $160 million, $174 million and $165 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2008, 2007 and 2006 amounted to $44 million, $54 million and $34 million, respectively. Services provided by PEF to PEC during 2008, 2007 and 2006 amounted to $12 million, $10 million and $8 million, respectively.

PEC and PEF participate in an internal money pool, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is also used to settle intercompany balances. The weighted-average interest rate for the money pool was 3.29%, 5.49% and 5.17% at December 31, 2008, 2007 and 2006, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded insignificant interest expense related to the money pool for all the years presented.

Progress Fuels sold coal to PEF at cost in 2007 and 2006. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $2 million and $321 million for the years ended December 31, 2007 and 2006, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as a separate business segment. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for 2007 and 2006 transactions between PEF and businesses included in the Corporate and Other segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and businesses included in the Corporate and Other segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2007 and 2006 were not significant.

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2008					
Revenues					
Unaffiliated	**$4,429**	**$4,730**	**$8**	**$ –**	**$9,167**
Intersegment	**–**	**1**	**361**	**(362)**	**–**
Total revenues	**4,429**	**4,731**	**369**	**(362)**	**9,167**
Depreciation, amortization and accretion	**518**	**306**	**15**	**–**	**839**
Interest income	**12**	**9**	**38**	**(35)**	**24**
Total interest charges, net	**207**	**208**	**259**	**(35)**	**639**
Income tax expense (benefit)	**298**	**181**	**(84)**	**–**	**395**
Segment profit (loss)	**531**	**383**	**(141)**		**773**
Total assets	**13,165**	**12,471**	**17,483**	**(13,246)**	**29,873**
Capital and investment expenditures	**939**	**1,601**	**33**	**(13)**	**2,560**
As of and for the year ended December 31, 2007					
Revenues					
Unaffiliated	$4,385	$4,748	$ 20	$ –	$9,153
Intersegment	–	1	393	(394)	–
Total revenues	4,385	4,749	413	(394)	9,153
Depreciation, amortization and accretion	519	366	20	–	905
Interest income	21	9	55	(51)	34
Total interest charges, net	210	173	258	(53)	588
Income tax expense (benefit)	295	144	(105)	–	334
Segment profit (loss)	498	315	(120)	–	693
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204
As of and for the year ended December 31, 2006					
Revenues					
Unaffiliated	$4,086	$4,638	$ –	$ –	$8,724
Intersegment	–	1	729	(730)	–
Total revenues	4,086	4,639	729	(730)	8,724
Depreciation, amortization and accretion	571	404	36	–	1,011
Interest income	25	15	85	(66)	59
Total interest charges, net	215	150	326	(67)	624
Income tax expense (benefit)	265	193	(119)	–	339
Segment profit (loss)	454	326	(229)	–	551
Total assets	11,999	8,648	15,394	(11,266)	24,775
Capital and investment expenditures	808	741	12	(9)	1,552

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. The components of other, net as shown on the accompanying Consolidated Statements of Income for the years ended December 31 were as follows:

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

(a) Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 Communications, Inc. stock received as part of the sale of our interest in PT LLC (See Note 3F). These gains are prior to the consideration of minority interest.

(b) On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

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

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

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	2008	2007
PEC		
MGP and other sites[a]	$16	$16
PEF		
Remediation of distribution and substation transformers	22	31
MGP and other sites	15	17
Total PEF environmental remediation accruals[b]	37	48
Total Progress Energy environmental remediation accruals	$53	$64

[a] Expected to be paid out over one to five years
[b] Expected to be paid out over one to 15 years

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

PEC

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

Including the Ward Transformer site located in Raleigh, N.C. (Ward), and MGP sites discussed below, for the year ended December 31, 2008, PEC accrued approximately $8 million, of which $2 million was deferred, and spent approximately $8 million. These amounts primarily relate to the Ward site. For the year ended December 31, 2007, including the Carolina Transformer site, the Ward site and MGP sites discussed below, PEC's accrual was reduced by a net amount of approximately $2 million and PEC spent approximately $4 million. For the year ended December 31, 2006, PEC accrued approximately $21 million and spent approximately $6 million. The 2006 accrual included $12 million for the minimum estimated total remediation cost for all of PEC's remaining MGP sites based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million.

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

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. During 2007, the PRP agreement was amended to include an additional participating PRP, which reduced, on an interim basis, PEC's proportionate responsibility for funding the remediation. During 2008, PEC increased its accrual due to an increase in the estimated scope of work. At December 31, 2008 and 2007, PEC's recorded liability for the site was approximately $7 million and $6 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed a complaint seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. The complaint names 28 parties that did not sign a tolling agreement with PEC, which was entered into by over 200 PRPs. The tolling agreement suspends the running of the statute of limitations for determination of cost recovery from PRPs at the Ward site. The litigation has been stayed to allow the parties to explore private settlements. The outcome of these matters cannot be predicted.

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

PEF

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution operations and maintenance expense (O&M) costs will not be recoverable through the ECRC. Based on historical experience, PEF projects costs will be between approximately $3 million and $4 million per year. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. For the year ended December 31, 2007, PEF accrued approximately $10 million due to an increase in estimated remediation costs and spent approximately $22 million related to the remediation of transformers. For the year ended December 31, 2006, PEF accrued approximately $42 million due to additional sites expected to require remediation and spent approximately $19 million related to the remediation of transformers. At December 31, 2008 and 2007, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the previous table, relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2008, PEF made no accruals and spent approximately $2 million. For the year ended December 31, 2007, PEF made no accruals and spent approximately $1 million. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures were not material to our results of operations or financial condition.

B. Air and Water Quality

At December 31, 2008 and 2007, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects. At December 31, 2007, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.225 billion, including $902 million at PEC and $323 million at PEF. PEC completed installation of controls to meet the requirements of the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) in 2007.

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

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

PEF is continuing construction of its in-process emission control projects. On December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire Crystal River Units No.1 and No. 2 (CR1 and CR2) as coal-fired units and complete construction of its emission control projects at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which is anticipated to be around 2020.

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

As discussed in Note 7B, in June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance for the jointly owned units, in 2005 PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2008 and 2007, the amount of the liability was $10 million and $30 million, respectively, based upon the respective estimates for the remaining Clean Smokestacks Act compliance costs. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. Because PEC has taken a system-wide compliance approach, its North Carolina retail ratepayers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail ratepayers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On November 2, 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part the Clean Smokestacks amortization, and subsequently reclassified $29 million of indemnification expense to Clean Smokestacks amortization. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service (See Note 7B).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

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

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

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.078 billion, $2.360 billion and $1.628 billion for 2008, 2007 and 2006, respectively.

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

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2009 to 2028. These purchased power contracts generally provide for capacity and energy payments.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW (19 percent of net output) of capacity through 2009 with an estimated remaining 2009 payment of approximately $29 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $90 million, $77 million and $80 million for 2008, 2007 and 2006, respectively.

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

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

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

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

PEF has ongoing purchased power contracts with certain QFs for 786 MW of firm capacity with expiration dates ranging from 2009 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $273 million, $288 million and $277 million for 2008, 2007 and 2006, respectively. At December 31, 2008, minimum expected future capacity payments under these contracts were $263 million, $267 million, $281 million, $292 million and $288 million for 2009 through 2013, respectively, and $2.751 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In June 2008, PEC entered into a conditional contract with an interstate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from May 2011 through April 2031. The estimated total cost to PEC associated with this agreement is approximately $487 million. The transaction is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of this agreement, the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In July 2008, PEC entered into an amendment to an existing transportation service agreement with an intrastate pipeline for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through May 2030. The total additional cost to PEC associated with this amendment is estimated to be approximately $54 million. The amendment is subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of this agreement, the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.086 billion. The contracts are subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. In addition to the FGT contracts, during 2008, PEF entered into additional gas supply and transportation arrangements for the period from 2010 through 2025 that are subject to certain conditions. The total current notional cost of these additional agreements is estimated to be approximately $849 million. Due to the conditions of these agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $1.018 billion, $698 million and $387 million for 2008, 2007 and 2006, respectively.

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

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

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and PEF service agreements related to the Hines Energy Complex and the Bartow plant. Our payments under these agreements were $110 million, $75 million and $100 million for 2008, 2007 and 2006, respectively.

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

(in millions)	Capital	Operating
2009	$29	$48
2010	28	29
2011	28	23
2012	28	38
2013	36	64
Thereafter	272	955
Minimum annual payments	421	$1,157
Less amount representing imputed interest	(182)	
Present value of net minimum lease payments under capital leases	$239	

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

B. Leases

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

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

(in millions)	2008	2007
Buildings	$267	$267
Less: Accumulated amortization	(28)	(20)
Total	$239	$247

At December 31, 2008, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

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

In 2007, PEF entered into a 632-MW (100 percent of net output) tolling purchased power agreement, which is classified as an operating lease. The agreement calls for minimum annual payments of approximately $28 million from June 2012 through May 2027, for a total of approximately $420 million.

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for minimum annual payments of approximately $5 million from 2007 through 2026, for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded in our 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. Due to the conditions of the agreement, the capital lease was not recorded on our Consolidated Balance Sheets until 2007.

In 2006, PEF entered into an agreement for 116.6-MW (100 percent of net output) purchased power, which is classified as a capital lease of the related plant. Due to the conditions of the agreement, the capital lease will not be recorded on our Consolidated Balance Sheets until approximately 2011. Therefore, this capital lease is not included in the table above. The agreement calls for minimum annual payments of approximately $7 million from 2012 through November 2036, for a total of approximately $170 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $8 million, $6 million, $5 million, $2 million and $1 million for 2009 through 2013, respectively. Rents received under these operating leases totaled $9 million, $8 million and $9 million for 2008, 2007 and 2006, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $10 million for 2009 and none thereafter. PEC's rents received are contingent upon usage and totaled $33 million each for 2008 and 2007 and $31 million for 2006. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $81 million, $78 million and $72 million for 2008, 2007 and 2006, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2009 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2008, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2008, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, which are within the scope of FIN 45. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2008, the estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. At December 31, 2008 and 2007, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $61 million and $80 million, respectively. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. Other Commitments and Contingencies

SPENT NUCLEAR FUEL MATTERS

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

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims. The Utilities have asserted nearly

$91 million in damages incurred between January 31, 1998 and December 31, 2005, the time period set by the court for damages in this case. The Utilities will be free to file subsequent damage claims as they incur additional costs.

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted (1) that pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities, and (3) a number of tort claims are related to the contracts.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.* (the Florida Global Case), asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003, and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. The parties are currently engaged in discovery in the Florida Global Case.

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

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow pursuant to a defined tax event. Upon the successful resolution of the IRS audit of the Earthco synthetic fuels facilities in 2006, and pursuant to a settlement agreement, the escrow totaling $42 million as of December 31, 2006, was paid to Global in January 2007.

In January 2008, Global agreed to simplify the Florida action by dismissing the tort claims. The Florida Global Case continues now under contract theories alone. The case is scheduled to go to trial in June 2009. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the Condensed Consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The annual interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2008, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only. The Non-guarantor Subsidiary column includes the consolidated financial results of our wholly owned subsidiary PEC. The Other column includes the consolidated financial results of all other non-guarantor subsidiaries, and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2008 (in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,738	$4,429	$–	$9,167
Operating expenses					
Fuel used in electric generation	–	1,675	1,346	–	3,021
Purchased power	–	953	346	–	1,299
Operation and maintenance	3	813	1,030	(26)	1,820
Depreciation, amortization and accretion	–	306	518	15	839
Taxes other than on income	–	309	198	1	508
Other	–	1	(5)	1	(3)
Total operating expenses	3	4,057	3,433	(9)	7,484
Operating (loss) income	(3)	681	996	9	1,683
Other income (expense)					
Interest income	11	9	12	(8)	24
Allowance for equity funds used during construction	–	95	27	–	122
Other, net	–	(18)	4	(3)	(17)
Total other income (expense), net	11	86	43	(11)	129
Interest charges					
Interest charges	201	263	219	(4)	679
Allowance for borrowed funds used during construction	–	(28)	(12)	–	(40)
Total interest charges, net	201	235	207	(4)	639
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(193)	532	832	2	1,173
Income tax (benefit) expense	(85)	172	298	10	395
Equity in earnings of consolidated subsidiaries	941	–	–	(941)	–
Minority interest in subsidiaries' income, net of tax	–	(5)	–	–	(5)
Income (loss) from continuing operations	833	355	534	(949)	773
Discontinued operations, net of tax	(3)	60	–	–	57
Net income (loss)	$830	$415	$534	$(949)	$830

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2007 (in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Operating expenses					
Fuel used in electric generation	–	1,764	1,381	–	3,145
Purchased power	–	882	302	–	1,184
Operation and maintenance	10	834	1,024	(26)	1,842
Depreciation, amortization and accretion	–	369	519	17	905
Taxes other than on income	–	309	192	–	501
Other	–	20	(2)	12	30
Total operating expenses	10	4,178	3,416	3	7,607
Operating (loss) income	(10)	590	969	(3)	1,546
Other income (expense)					
Interest income	27	8	21	(22)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	6	(11)	(7)
Total other income (expense), net	27	47	37	(33)	78
Interest charges					
Interest charges	203	210	215	(23)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	210	(23)	588
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(186)	439	796	(13)	1,036
Income tax (benefit) expense	(79)	117	295	1	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	–	(9)
Income (loss) from continuing operations	489	313	501	(610)	693
Discontinued operations, net of tax	15	30	–	(234)	(189)
Net income (loss)	$504	$343	$501	$(844)	$504

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Operating revenues	$–	$4,637	$4,086	$1	$8,724
Operating expenses					
Fuel used in electric generation	–	1,835	1,173	–	3,008
Purchased power	–	766	334	–	1,100
Operation and maintenance	14	684	930	(45)	1,583
Depreciation, amortization and accretion	–	406	571	34	1,011
Taxes other than on income	–	309	191	–	500
Other	–	21	–	14	35
Total operating expenses	14	4,021	3,199	3	7,237
Operating (loss) income	(14)	616	887	(2)	1,487
Other income (expense)					
Interest income	47	15	25	(28)	59
Allowance for equity funds used during construction	–	17	4	–	21
Other, net	(80)	23	21	(1)	(37)
Total other (expense) income, net	(33)	55	50	(29)	43
Interest charges					
Interest charges	276	187	217	(49)	631
Allowance for borrowed funds used during construction	–	(5)	(2)	–	(7)
Total interest charges, net	276	182	215	(49)	624
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	489	722	18	906
Income tax (benefit) expense	(123)	174	265	23	339
Equity in earnings of consolidated subsidiaries	779	–	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(16)	–	–	(16)
Income (loss) from continuing operations	579	299	457	(784)	551
Discontinued operations, net of tax	(8)	400	–	(372)	20
Net income (loss)	$571	$699	$457	$(1,156)	$571

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$8,790	$9,385	$118	$18,293
Current assets					
Cash and cash equivalents	88	73	18	1	180
Receivables, net	–	363	502	2	867
Notes receivable from affiliated companies	34	44	55	(133)	–
Inventory	–	606	633	–	1,239
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Prepayments and other current assets	48	169	137	(6)	348
Total current assets	170	1,916	1,570	(136)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Nuclear decommissioning trust funds	–	417	672	–	1,089
Goodwill	–	–	–	3,655	3,655
Other assets and deferred debits	155	196	295	103	749
Total deferred debits and other assets	12,079	1,937	2,210	(8,166)	8,060
Total assets	$12,249	$12,643	$13,165	$(8,184)	$29,873
CAPITALIZATION AND LIABILITIES					
Capitalization					
Common stock equity	$8,687	$3,519	$4,301	$(7,820)	$8,687
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	–	93
Minority interest	–	3	–	3	6
Long-term debt, affiliate	–	309	–	(37)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	7,869	(7,854)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	–	(206)	–
Derivative liabilities	31	380	82	–	493
Other current liabilities	220	964	773	(14)	1,943
Total current liabilities	820	1,921	965	(220)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Accrued pension and other benefits	10	540	856	188	1,594
Other liabilities and deferred credits	35	941	1,377	(4)	2,349
Total deferred credits and other liabilities	46	2,675	4,331	(110)	6,942
Total capitalization and liabilities	$12,249	$12,643	$13,165	$(8,184)	$29,873

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$7,600	$8,880	$125	$16,605
Current assets					
Cash and cash equivalents	185	43	25	2	255
Receivables, net	–	574	446	102	1,122
Notes receivable from affiliated companies	157	149	–	(306)	–
Inventory	–	484	510	–	994
Regulatory assets	–	6	148	–	154
Assets to be divested	–	48	–	4	52
Prepayments and other current assets	21	188	110	(94)	225
Total current assets	363	1,492	1,239	(292)	2,802
Deferred debits and other assets					
Investment in consolidated subsidiaries	10,942	–	–	(10,942)	–
Regulatory assets	–	266	680	–	946
Nuclear decommissioning trust funds	–	580	804	–	1,384
Goodwill	–	1	–	3,654	3,655
Other assets and deferred debits	149	729	352	(284)	946
Total deferred debits and other assets	11,091	1,576	1,836	(7,572)	6,931
Total assets	$11,454	$10,668	$11,955	$(7,739)	$26,338
CAPITALIZATION AND LIABILITIES					
Common stock equity	$8,395	$3,052	$3,752	$(6,804)	$8,395
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	–	93
Minority interest	–	81	–	3	84
Long-term debt, affiliate	–	309	–	(38)	271
Long-term debt, net	2,597	2,686	3,183	–	8,466
Total capitalization	10,992	6,162	6,994	(6,839)	17,309
Current liabilities					
Current portion of long-term debt	–	577	300	–	877
Short-term debt	201	–	–	–	201
Notes payable to affiliated companies	–	227	154	(381)	–
Derivative liabilities	–	38	19	–	57
Liabilities to be divested	–	8	–	–	8
Other current liabilities	215	1,199	697	48	2,159
Total current liabilities	416	2,049	1,170	(333)	3,302
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	59	936	(634)	361
Regulatory liabilities	–	1,330	1,098	126	2,554
Accrued pension and other benefits	12	347	459	(55)	763
Other liabilities and deferred credits	34	721	1,298	(4)	2,049
Total deferred credits and other liabilities	46	2,457	3,791	(567)	5,727
Total capitalization and liabilities	$11,454	$10,668	$11,955	$(7,739)	$26,338

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2008

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	S(90)	S221	S1,061	S26	S1,218
Investing activities					
Gross property additions	–	(1,553)	(760)	(20)	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	8	5	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(682)	(118)	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	626	120	1,534
Changes in advances to affiliated companies	123	105	(55)	(173)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Other investing activities	20	8	–	(30)	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,042)	(127)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to minority interests of consolidated subsidiaries	–	(85)	–	–	(85)
Changes in advances from affiliated companies	–	(21)	(154)	175	–
Contributions from parent	–	85	15	(100)	–
Other financing activities	–	1	(19)	(8)	(26)
Net cash (used) provided by financing activities	(42)	1,216	(26)	100	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(7)	(1)	(75)
Cash and cash equivalents at beginning of year	185	43	25	2	255
Cash and cash equivalents at end of year	S88	S73	S18	S1	S180

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2007

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$76	$489	$1,018	$(331)	$1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	10	614	675
Purchases of available-for-sale securities and other investments	–	(640)	(603)	(170)	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	622	169	1,452
Changes in advances to affiliated companies	(99)	(112)	24	187	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(4)	33	30
Net cash provided (used) by investing activities	231	(1,291)	(892)	495	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(143)	153	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	176	–	–	–	176
Net increase in short-term debt	25	–	–	–	25
Proceeds from issuance of long-term debt, net	–	739	–	–	739
Retirement of long-term debt	–	(124)	(200)	–	(324)
Cash distributions to minority interests of consolidated subsidiaries	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	154	(305)	–
Contributions from parent	–	10	21	(31)	–
Other financing activities	–	49	(4)	20	65
Net cash (used) provided by financing activities	(275)	805	(172)	(163)	195
Net increase (decrease) in cash and cash equivalents	32	3	(46)	1	(10)
Cash and cash equivalents at beginning of year	153	40	71	1	265
Cash and cash equivalents at end of year	$185	$43	$25	$2	$255

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiary	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,110	$1,094	$(1,498)	$2,001
Investing activities					
Gross property additions	–	(865)	(705)	(2)	(1,572)
Nuclear fuel additions	–	(12)	(102)	–	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,242	5	410	1,657
Purchases of available-for-sale securities and other investments	(919)	(625)	(896)	(12)	(2,452)
Proceeds from available-for-sale securities and other investments	898	724	1,006	3	2,631
Changes in advances to affiliated companies	409	(39)	(24)	(346)	–
Proceeds from repayment of long-term affiliate debt	131	–	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	–	(287)	–
Other investing activities	(63)	(6)	(6)	52	(23)
Net cash provided (used) by investing activities	743	419	(722)	(313)	127
Financing activities					
Issuance of common stock	185	–	–	–	185
Dividends paid on common stock	(607)	–	–	–	(607)
Dividends paid to parent	–	(1,135)	(339)	1,474	–
Net decrease in short-term debt	–	(102)	(73)	–	(175)
Proceeds from issuance of long-term debt, net	397	–	–	–	397
Retirement of long-term debt	(2,091)	(109)	–	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	–	131	–
Cash distributions to minority interests of consolidated subsidiaries	–	(79)	–	–	(79)
Changes in advances from affiliated companies	–	(243)	(11)	254	–
Contributions from parent	–	67	–	(67)	–
Other financing activities	(8)	4	(3)	18	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	(426)	1,810	(2,468)
Net decrease in cash and cash equivalents	(86)	(199)	(54)	(1)	(340)
Cash and cash equivalents at beginning of year	239	239	125	2	605
Cash and cash equivalents at end of year	$153	$40	$71	$1	$265

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

(in millions except per share data)		First	Second	Third	Fourth
2008					
Operating revenues		**$2,066**	**$2,244**	**$2,696**	**$2,161**
Operating income		**365**	**406**	**591**	**321**
Income from continuing operations		**149**	**200**	**308**	**116**
Net income		**209**	**205**	**309**	**107**
Common stock data					
Basic earnings per common share					
Income from continuing operations		**0.58**	**0.77**	**1.18**	**0.44**
Net income		**0.81**	**0.79**	**1.19**	**0.41**
Diluted earnings per common share					
Income from continuing operations		**0.58**	**0.77**	**1.18**	**0.44**
Net income		**0.81**	**0.79**	**1.18**	**0.41**
Dividends declared per common share		**0.615**	**0.615**	**0.615**	**0.620**
Market price per share	**– High**	**49.16**	**43.58**	**45.52**	**45.60**
	– Low	**40.54**	**41.00**	**40.11**	**32.60**
2007					
Operating revenues		$2,072	$2,129	$2,750	$2,202
Operating income		351	301	610	284
Income from continuing operations		149	138	311	95
Net income (loss)		275	(193)	319	103
Common stock data					
Basic earnings per common share					
Income from continuing operations		0.59	0.54	1.21	0.37
Net income (loss)		1.08	(0.75)	1.24	0.40
Diluted earnings per common share					
Income from continuing operations		0.59	0.54	1.21	0.37
Net income (loss)		1.08	(0.75)	1.24	0.40
Dividends declared per common share		0.610	0.610	0.610	0.615
Market price per share	– High	51.60	52.75	49.48	50.25
	– Low	47.05	45.15	43.12	44.75

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 *(in millions, except per share data)*	**2008**	2007	2006	2005	2004
Operating results					
Operating revenues	**$9,167**	$9,153	$8,724	$7,948	$7,168
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**773**	693	551	523	552
Net income	**830**	504	571	697	759
Per share data					
Basic earnings					
Income from continuing operations	**$2.97**	$2.71	$2.20	$2.12	$2.28
Net income	**3.19**	1.97	2.28	2.82	3.13
Diluted earnings					
Income from continuing operations	**2.96**	2.70	2.20	2.12	2.27
Net income	**3.18**	1.96	2.28	2.82	3.12
Assets[(a)]	**$29,873**	$26,338	$25,832	$27,083	$26,100
Capitalization and debt					
Common stock equity[(b)]	**$8,687**	$8,395	$8,259	$8,011	$7,606
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**6**	84	10	36	29
Long-term debt, net[(c)]	**10,659**	8,737	8,835	10,446	9,521
Current portion of long-term debt	–	877	324	513	349
Short-term debt	**1,050**	201	–	175	684
Capital lease obligations	**239**	247	72	18	19
Total capitalization and debt[(b)]	**$20,734**	$18,634	$17,593	$19,292	$18,301
Other financial data					
Return on average common stock equity (percent)	**9.59**	5.97	7.05	8.92	9.99
Ratio of earnings to fixed charges	**2.66**	2.62	2.35	2.33	2.49
Number of common shareholders of record	**55,919**	58,991	64,899	67,638	70,159
Book value per common share	**$33.13**	$32.55	$32.61	$32.24	$31.28
Dividends declared per common share	**$2.47**	$2.45	$2.43	$2.38	$2.32
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**46,771**	51,163	48,770	52,306	50,782
Nuclear	**30,565**	30,336	30,602	30,120	30,445
Combustion turbines/combined cycle	**15,557**	13,319	11,857	11,349	9,695
Hydro	**429**	415	594	749	802
Purchased	**14,956**	14,994	14,664	14,566	13,466
Total energy supply (Company share)	**108,278**	110,227	106,487	109,090	105,190
Joint-owner share[(d)]	**5,780**	5,351	5,224	5,388	5,395
Total system energy supply	**114,058**	115,578	111,711	114,478	110,585

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

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

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

[(d)] Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned.

We use ongoing earnings per share to evaluate our operations and to establish goals for management and employees. We believe this presentation is appropriate and enables investors to more accurately compare our ongoing financial performance over the periods presented. Ongoing earnings as presented here may not be comparable to similarly titled measures used by other companies. Reconciling adjustments from ongoing earnings per share to GAAP earnings per share are as follows:

December 31	2008	2007	2006
Ongoing earnings per share	**$2.98**	$2.72	$2.44
Contingent value obligations mark-to-market	–	(0.01)	(0.10)
Discontinued operations	**0.22**	(0.74)	0.08
Loss on debt redemption	–	–	(0.14)
Valuation allowance	**(0.01)**	–	–
Reported GAAP earnings per share	**$3.19**	$1.97	$2.28

Contingent Value Obligation (CVO) Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, we issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuel facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are derivatives and, under GAAP, are recorded at fair value. Unrealized gains and losses from changes in fair value are recognized in earnings. Since changes in the fair value of the CVOs do not affect our underlying obligation, we do not consider the adjustment a component of ongoing earnings.

Discontinued Operations

The operations of businesses that have been sold or are in the process of being sold are reported as discontinued operations, and, therefore, we do not view these activities as representative of our ongoing operations. Our discontinued operations primarily include Terminals Operations and Synthetic Fuels businesses; Coal Mining businesses; CCO – Georgia Operations; Natural Gas Drilling and Production; CCO – DeSoto and Rowan Generation facilities; Progress Telecom, LLC, Dixie Fuels and other fuels businesses; and Progress Rail.

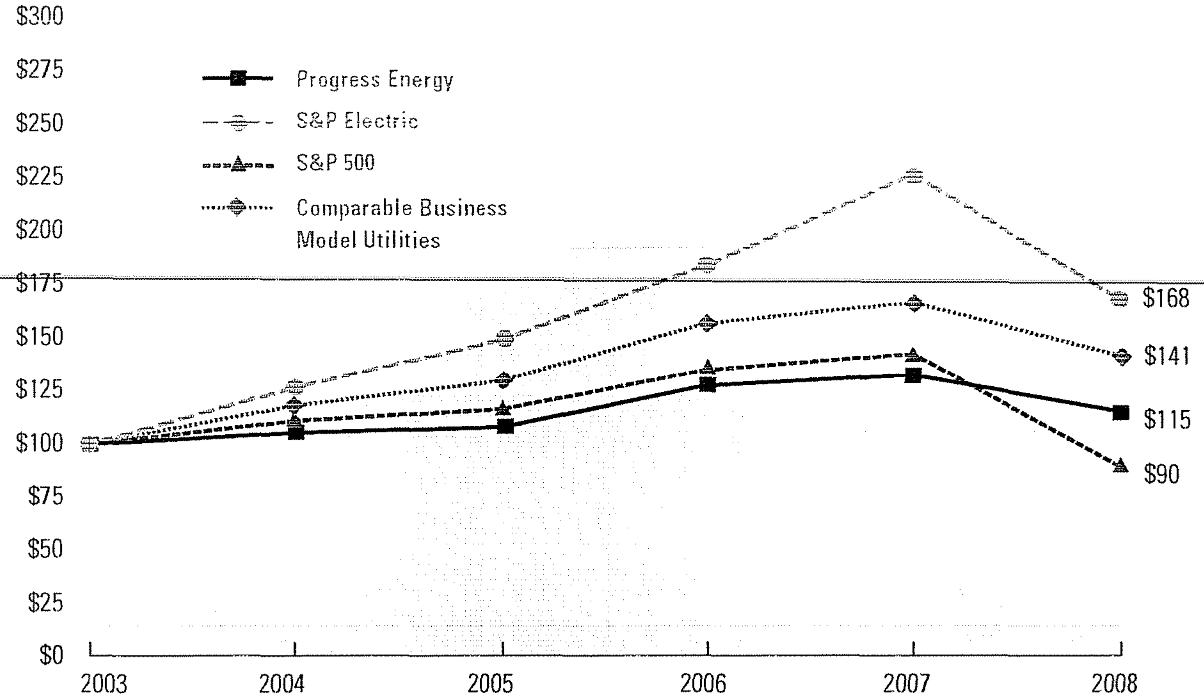
Loss on Redemption of Debt

In November 2006, the Parent redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. In December 2006, the Parent repurchased, pursuant to a tender offer, $550 million, or approximately 44.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. Due to the nonrecurring nature of this loss, we do not believe it is representative of our ongoing operations.

Valuation Allowance

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, we 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. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance, which more than offset the change in estimate. Management does not believe this net valuation allowance is representative of our ongoing operations.

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)	2003	2004	2005	2006	2007	2008
Progress Energy, Inc.	$100	$105	$108	$127	$132	$115
S&P 500 Index	100	111	116	135	142	90
Comparable Business Model Utilities	100	118	130	156	166	141
S&P Electric Index	100	127	149	183	226	168

*$100 invested on 12/31/2003 in Stock or Index. Including reinvestment of dividends. Fiscal year ending 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 2009 annual meeting of shareholders will be held May 13, 2009, 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, select Electronic Shareholder Communications and follow the instructions.

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 2009 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.

NYSE Certifications

Because Progress Energy's common stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 9, 2008. In addition, we have filed, as exhibits to the Annual Report on Form 10-K for the year ended December 31, 2008, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the Securities and Exchange Commission regarding the quality of our public disclosure.

Cautionary Statement

This annual 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, 2009

Dear Shareholder:

I am pleased to invite you to attend the 2009 Annual Meeting of the Shareholders of Progress Energy, Inc. The meeting will be held at 10:00 a.m. on May 13, 2009, 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 the approval of the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code.

We are pleased to take advantage of the new Securities and Exchange Commission rules that allow companies to electronically deliver proxy materials to their shareholders. We believe that this new process will allow 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, 2009, 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 OF THESE 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 2009.

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 13, 2009

The Annual Meeting of the Shareholders of Progress Energy, Inc. (the "Company") will be held ~~at 10:00 a.m. on May 13, 2009, 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 twelve (12) directors of the Company, each to serve a one-year term. The Company 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 Company recommends a vote **FOR** the ratification of the selection of Deloitte & Touche LLP as the Company's independent registered public accounting firm.

(3) Act upon a proposal to approve the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code. The Company recommends a vote **FOR** this 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 6, 2009, 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, 2009

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 13, 2009, 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, 2009.

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.

Copies of our Annual Report on Form 10-K for the year ended December 31, 2008, 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.

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, 2009, as set forth in this Proxy Statement; and **"FOR"** the proposal to approve the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code 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. 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, in certain circumstances, vote the shares at its discretion. 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 election of directors and 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.

With respect to "nonroutine" matters, a brokerage firm, bank or other nominee is not permitted under the SRO rules to vote its clients' shares if the clients do not provide instructions. The brokerage firm 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 2009 Annual Meeting of Shareholders, one nonroutine matter, a proposal to approve the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code, 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 6, 2009, 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 6, 2009, there were outstanding 278,467,434 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 proposal regarding the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code will require the affirmative vote of a majority of the votes cast on the proposal. 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 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 proposal regarding the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code 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 our quarterly report on Form 10-Q for the second quarter of fiscal year 2009. A copy of this quarterly report 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 2009 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 13), the Board of Directors nominates the following 12 nominees to serve as directors with terms expiring in 2010 and until their respective successors are elected and qualified: James E. Bostic, Jr., Harris E. DeLoach, Jr., James B. Hyler, Jr., William D. Johnson, Robert W. Jones, W. Steven Jones, 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 among any of the nominees for director or among any nominee and any director or officer of the Company or its subsidiaries, and there is no arrangement or understanding between any nominee and any other person pursuant to which the 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 12 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 names of the 12 nominees for election to the Board of Directors, along with their ages, principal occupations or employment for the past five years, and current directorships of public companies, are set forth below. No information is included regarding David L. Burner, who will retire from the Board at the Annual Meeting of Shareholders on May 13, 2009. No decision has been made regarding which nominees will replace Mr. Burner on the various Board committees on which he currently serves. James B. Hyler, Jr., who was elected by the Board on September 18, 2008, is a director standing for election to the Board by our shareholders for the first time. Mr. Hyler 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 7 of this Proxy Statement.

The Board of Directors recommends a vote **"FOR"** each nominee for director.

Nominees for Election

JAMES E. BOSTIC, JR., age 61, is Managing Director of HEP & Associates, a business consulting firm, and a partner of Coleman Lew & Associates, Inc., an executive search consulting firm. He was formerly Executive Vice President of Georgia-Pacific Corporation, a manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals. 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 64, is Chairman, President and Chief Executive Officer of Sonoco Products Company, a manufacturer of paperboard and paper and plastic packaging products. He previously served as President and CEO of Sonoco Products Company from July 2000 to April 2005. Mr. DeLoach has served as a director of the Company since 2006. He also serves as a director of Sonoco Products Company and Goodrich Corporation. 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.

JAMES B. HYLER, JR., age 61, is retired Vice Chairman and Chief Operating Officer of First Citizens Bank. He was a former auditor with Ernst & Young for ten years prior to becoming Chief Financial Officer and then President of First Citizens Bank. Mr. Hyler has served as a director of the Company since 2008. He is a member of the Board's Audit and Corporate Performance Committee and the Finance Committee.

WILLIAM D. JOHNSON, age 55, is Chairman, President and Chief Executive Officer of Progress Energy. He 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 (previously 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, North Carolina, law office of Hunton & Williams LLP, where he specialized in the representation of utilities. He has served as a director of the Company since 2007.

ROBERT W. JONES, age 58, is a Senior Advisor of Morgan Stanley, a global provider of financial services to companies, governments and investors. Mr. Jones has held various positions with Morgan Stanley since 1974, most recently serving as Managing Director and Vice Chairman of Investment Banking. He has served as a director of the Company since 2007. Mr. Jones is a member of the Board's Finance Committee and the Organization and Compensation Committee.

W. STEVEN JONES, age 57, is Dean (Emeritus) and Professor of Strategy and Organizational Behavior at UNC Kenan-Flagler Business School at the University of North Carolina at Chapel Hill. Mr. Jones is a former CEO and Managing Director of Suncorp-Metway Ltd. in Brisbane, Queensland, Australia, which provides banking, insurance and investing services. He has served as a director of the Company since 2005 and also serves as a director of Premiere Global Services. Mr. Jones is a member of the Board's Nuclear Project Oversight Committee, the Operations and Nuclear Oversight Committee and the Organization and Compensation Committee.

E. MARIE MCKEE, age 58, 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. She has served as a director of the Company and its predecessors since 1999. 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 67, is Chairman of Ridgeway Farm, LLC, a limited liability company engaged in farming and timber management. He is a former Managing Director of Dillon, Read & Co., an investment banking firm. He has served as a director of the Company and its predecessors since 1999 and also serves as a director of Hess Corporation and Sonoco Products Company. Mr. Mullin is the Board's Lead Director and Chair of the Board's Governance Committee. He is a member of the Board's Executive Committee, the Finance Committee and the Organization and Compensation Committee.

CHARLES W. PRYOR, JR., age 64, is Chairman of Urenco Investments, Inc., a global provider of value added services and technology to the nuclear generation industry worldwide. He also has served as President of Urenco Investments Inc. since 2004. Dr. Pryor served as President and CEO of the Utilities Business Group of British Nuclear Fuels from 2002 to 2004. He has served as a director of the Company since 2007 and also serves as a director of DTE Energy. Dr. 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.

CARLOS A. SALADRIGAS, age 60, is Chairman and CEO of Regis HRG, which offers a full suite of outsourced human resources services to small and mid-sized businesses. He previously served as Chairman, from 2002 to 2007, and Vice Chairman, from 2007 to 2008, of Premier American Bank in Miami, Florida. In 2002, he retired as Chief Executive Officer of ADP TotalSource (previously the Vincam Group, Inc.), a Miami-based human resources outsourcing company that provides services to small and mid-sized businesses. Mr. Saladrigas has served as a director of the Company since 2001 and also serves as a director of Advance Auto Parts, Inc. and MBF Healthcare Acquisition Corp. He is a member of the Board's Audit and Corporate Performance Committee and the Finance Committee.

THERESA M. STONE, age 64, is Executive Vice President and Treasurer of the Massachusetts Institute of Technology Corporation since February 2007. She previously served as Executive Vice President and Chief Financial Officer of Jefferson-Pilot Financial (now Lincoln Financial Group) from November 2001 to March 2006. She also served as President of Lincoln Financial Media Company (formerly known as Jefferson-Pilot Communications Company) from July 1997 to May 2006. Ms. Stone has served as a director of the Company since 2005. She 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 66, is retired Chairman and Chief Executive Officer of the Institute of Nuclear Power Operations, a nuclear industry-sponsored nonprofit organization. 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, 2008. 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 Bank and Trust Company One Lincoln Street Boston, MA 02111	24,501,247[1]	9.3

[1] Consists of shares of Common Stock held by State Street Bank and Trust Company, acting in various fiduciary capacities. State Street Bank and Trust Company has sole power to vote with respect to 10,775,764 shares, sole dispositive power with respect to 0 shares, shared power to vote with respect to 1,118,469 shares and shared power to dispose of 24,501,247 shares. State Street Bank and Trust Company has disclaimed beneficial ownership of all shares of Common Stock. (Based solely on information contained in a Schedule 13G filed by State Street Bank and Trust Company on February 17, 2009.)

MANAGEMENT OWNERSHIP OF COMMON STOCK

The following table describes the beneficial ownership of our Common Stock and ownership of Common Stock units as of February 27, 2009, 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. 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. As of February 27, 2009, 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]
James E. Bostic, Jr.	8,311[1]
David L. Burner*	7,000[1]
Harris E. DeLoach, Jr.	5,000
James B. Hyler, Jr.	1,000
William D. Johnson	118,467[2]
Robert W. Jones	1,000
W. Steven Jones	1,000
Jeffrey J. Lyash	21,238[2]
John R. McArthur	35,981[2]
E. Marie McKee	3,500[1]
Mark F. Mulhern	31,833[2]
John H. Mullin, III	10,000[1,3]
Charles W. Pryor, Jr.	242
Carlos A. Saladrigas	7,000[1]
Peter M. Scott III (Retired effective September 1, 2008)	110,744[2,4]
Theresa M. Stone	1,000
Alfred C. Tollison, Jr.	1,000
Lloyd M. Yates	20,879[2]
Shares of Common Stock and Units beneficially owned by all Directors and executive officers of the Company as a group (24 persons)	485,141[5]

* Retiring from the Board at the Annual Meeting of Shareholders on May 13, 2009.

[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
David L. Burner	6,000
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	31,134	—
Jeffrey J. Lyash	7,300	—
John R. McArthur	9,167	—
Mark F. Mulhern	14,800	7,000
Peter M. Scott III	—	52,000
Lloyd M. Yates	8,500	—

[3] Mr. Mullin has a line of credit with Merrill Lynch for which he has pledged as collateral 4,000 shares of Company Common Stock that he owns. No amount is currently outstanding under the line of credit.

[4] Reflects shares of our Common Stock Mr. Scott owned as of September 30, 2008.

[5] 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.

Management 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 27, 2009:

Director	Directors' Deferred Compensation Plan	Non-Employee Director Stock Unit Plan
James E. Bostic, Jr.	9,813	7,989
David L. Burner	13,762	10,668
Harris E. DeLoach, Jr.	7,011	4,215
James B. Hyler, Jr.	389	1,500
Robert W. Jones	4,139	2,856
W. Steven Jones	8,776	5,651
E. Marie McKee	25,157	10,668
John H. Mullin, III	17,597	11,133
Charles W. Pryor, Jr.	1,247	2,856
Carlos A. Saladrigas	8,922	5,787
Theresa M. Stone	8,685	5,651
Alfred C. Tollison, Jr.	6,694	4,215

The table below shows ownership as of February 27, 2009, 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 and 2002 Equity Incentive Plans ("PSSP") (see "Outstanding Equity Awards at Fiscal Year End Table" on page 48); (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 Equity Incentive Plan.

Officer	Long-Term Compensation Program	MICP	PSSP	PSSP Deferred	MDCP	RSUs
William D. Johnson	—	1,603	149,365	—	992	37,759
Jeffrey J. Lyash	—	—	39,130	—	294	18,517
John R. McArthur	—	—	39,858	—	—	17,923
Mark F. Mulhern	—	—	31,021	2,567	4,246	13,973
Peter M. Scott III	—	—	77,030	12,260	—	14,708
Lloyd M. Yates	—	2,503	39,130	5,972	148	18,517

TRANSACTIONS WITH RELATED PERSONS

There were no transactions in 2008 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.

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 2008 fiscal year were met except as follows: Each of James E. Bostic, Jr., David L. Burner, Richard L. Daugherty (retired from the Board on May 14, 2008), Harris E. DeLoach, Jr., Robert W. Jones, W. Steven Jones, E. Marie McKee, John H. Mullin, III, Charles W. Pryor, Jr., Carlos A. Saladrigas, Theresa M. Stone and Alfred C. Tollison, Jr. inadvertently failed to file on a timely basis a Form 4 with respect to a matching contribution that was made on February 26, 2008, under the Company's Non-Employee Directors Deferred Compensation Plan. A Form 4 reporting the transaction was filed by each individual on April 3, 2008.

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, NC 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*. This information is available in print to any shareholder who requests it at no charge.

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:

James E. Bostic, Jr.	E. Marie McKee
David L. Burner	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.

Additionally, the Board of Directors has determined that Richard L. Daugherty, who served as a member of the Board during a portion of 2008, 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 and are attached to this Proxy Statement as Exhibit B. 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 2008, 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. Mullin and Saladrigas are directors of companies that purchase electric energy from PEF. Mr. Robert W. Jones is an employee of Morgan Stanley, which has provided a variety of investment banking services to us during the past several years. Mr. W. Steven Jones serves as a director of a communications technology company that provided services to us in 2008. 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. 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 thirteen (13) members. The Board of Directors met nine times in 2008. Average attendance of the directors at the meetings of the Board and its committees held during 2008 was 95 percent, and no director attended less than 75 percent of all Board and his/her respective committee meetings held in 2008 except for Mr. Burner, who attended 73 percent of said meetings.

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 14, 2008, the date of the 2008 Annual Meeting of Shareholders, attended that meeting. Mr. Burner will retire from the Board at the Annual Meeting of Shareholders on May 13, 2009. No decision has been made regarding which nominees will replace him on the various Board committees on which he currently serves; however, we expect to file a Form 8-K regarding the election of any new directors as appropriate.

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 charters are available in print to any shareholder who requests them. Additionally, the charter of the Audit and Corporate Performance Committee is included as Exhibit C to this Proxy Statement. The current membership and functions of the standing Board committees, as of December 31, 2008, are discussed below.

Executive Committee

The Executive Committee is presently composed of one director who is an officer and four nonmanagement directors: Messrs. William D. Johnson—Chair, David L. Burner, Harris E. DeLoach, Jr., E. Marie McKee, John H. Mullin, III, 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 one meeting in 2008.

Audit and Corporate Performance Committee

The Audit and Corporate Performance Committee (the "Audit Committee") is presently composed of the following six nonmanagement directors: Ms. Theresa M. Stone—Chair, and Messrs. James E. Bostic, Jr., James B. Hyler, Jr., 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 2008.

Corporate Governance Committee

The Governance Committee is presently composed of the following five nonmanagement directors: Messrs. John H. Mullin, III—Chair/Lead Director, David L. Burner and Harris E. DeLoach 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 2008.

Finance Committee

The Finance Committee is presently composed of the following six nonmanagement directors: Messrs. David L. Burner—Chair, James B. Hyler, Jr., Robert W. Jones, John H. Mullin, III, 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 2008.

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 was formed in December 2008.

Operations and Nuclear Oversight Committee

The Operations and Nuclear Oversight Committee is presently composed of the following six nonmanagement directors: Messrs. Harris E. DeLoach, Jr.—Chair, James E. Bostic, Jr., W. Steven Jones, Charles W. Pryor, Jr., 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 three meetings in 2008.

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. Messrs. David L. Burner, Harris E. DeLoach, Jr., Robert W. Jones, W. Steven 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. For 2008, 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.

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;
- Performing benchmarking and competitive assessments;
- Designing incentive plans;
- Performing financial analysis of and determining shareholder value drivers; 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 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 officers of the Company shall provide staff support to the Compensation Committee. 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 five meetings in 2008.

Compensation Committee Interlocks and Insider Participation

None of the directors who served as members of the Compensation Committee during 2008 was our employee or former employee and none of them had any relationship requiring disclosure under Item 404 of Regulation S-K. During 2008, 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.

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, NC 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.

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 40 (the "named executive officers") for the services they provided to the Company in 2008. For 2008, the Company's named executive officers were:

- William D. Johnson, Chairman, President and Chief Executive Officer;
- Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired effective September 1, 2008);
- Mark F. Mulhern, Senior Vice President and Chief Financial Officer, effective September 1, 2008 (formerly Senior Vice President-Finance);
- John R. McArthur, Executive Vice President and Corporate Secretary, effective September 1, 2008 (formerly Senior Vice President and General Counsel);
- Jeffrey J. Lyash, President and Chief Executive Officer, Progress Energy Florida, Inc.; and
- Lloyd M. Yates, President and Chief Executive Officer, Progress Energy Carolinas, Inc.

The fourth part consists of the Compensation Committee's Report. Following the CD&A are the tables setting forth the 2008 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 percent to 10 percent range over a three- to five-year holding period. 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 sustained dividend growth, thus minimizing our stock price volatility.
- **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 area, as the industry enters a significant capital expenditure phase and the demand for additional 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 the incentives necessary to motivate the executives to perform in the best interests of the Company and its shareholders. The Committee also believes that it is in the best interests of the Company and its shareholders to have skilled, engaged and high-performing executives who can sustain the Company's ongoing performance.

In determining an individual executive officer's compensation opportunity, the Committee believes that the compensation opportunity must be competitive within the marketplace for the specific role of the 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. Additionally, from a market analysis standpoint, 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. To establish the appropriate compensation opportunity for each executive officer, the Company seeks to balance the value of the various elements of compensation to the Company against the perceived value of those elements to the executive officer.

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 performance.	Aids in attracting and retaining executives and rewards operating performance results that are consistent with reliable and efficient electric service.	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 aid in attracting and retaining executives.	Long-term
Supplemental Senior Executive Retirement Plan	Formula-based compensation, based on salary, bonus and eligible years of service.	Aids in attracting and retaining executive officers.	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; and (ii) retaining executives during transition following a change-in-control.	Long-term
Employment Agreements	Define Company's relationship with its executives and provide protection to each of the parties.	Aid in attracting and retaining executives.	Long-term
Executive Perquisites	Personal benefits awarded outside of base salaries.	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.	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 the various compensation program elements:

- link compensation with our short-term 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;

- balance the perceived value of compensation elements to our executives with our actual cost;

- 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 provide ease of administration.

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 68 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. In November 2007, the Committee retained Hewitt Associates ("Hewitt") as its independent executive compensation and benefits consultant to assist the Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, Hewitt reports directly to the Committee. Throughout the remainder of this CD&A, the term "compensation consultant" refers to Hewitt unless otherwise noted.

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;

- performing benchmarking and competitive assessments;

- designing incentive plans;

- performing financial analysis of and determining shareholder value drivers; and

- recommending appropriate performance metrics and financial targets.

Hewitt has not in 2009, and did not in 2008, provide any services or products to the Company other than those that are related to the Company's executive compensation and benefits program.

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 annual performance evaluations 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.

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 1) in which aspect of the value chain does the company participate: generation, transmission and/or delivery, and 2) 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, annual incentives and long-term incentives of our executive officers to compensation opportunities provided to executive officers of our peers. For 2008, the Committee approved the use of a peer group consisting of 18 integrated utilities (that is, utilities that have transmission, distribution and generation assets). The peer group was chosen based on many factors including revenue, market capitalization and percentage of regulated assets to total assets; the peer group also consists of the companies with which we primarily compete for executive talent. The table below lists the companies in the peer group we use for benchmarking purposes.

Allegheny Energy, Inc.	Edison International	Pinnacle West Capital Corporation
Ameren Corporation	Entergy Corporation	PPL Corporation
American Electric Power Company, Inc.	Exelon Corporation	SCANA Corporation
Dominion Resources, Inc.	FirstEnergy Corporation	Southern Company
DTE Energy Company	PG&E Corporation	Xcel Energy, Inc.
Duke Energy Corporation	FPL Group, Inc.	TECO Energy

The Committee believes this peer group is appropriate for overall compensation comparisons because it reflects the most appropriate and comparable employment markets for our executive officers. The Committee will continue to evaluate and monitor the peer group to ensure that it remains appropriate for such 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. However, the Committee bases its compensation decisions on the compensation principles discussed above, not on Section 162(m). The Committee believes the current design of our compensation program effectively links pay to performance and provides appropriate flexibility in determining amounts to be awarded. Therefore, the Committee has not adopted a policy requiring that executive compensation be deductible under Section 162(m).

STOCK OWNERSHIP GUIDELINES

To align the interests of our executives with the interests of shareholders, the Board of Directors adopted stock ownership guidelines for all executive officers. The guidelines are designed to ensure that our management maintains a personal stake in the Company through a significant equity investment 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 within five years of assuming his or her position. The required levels of ownership are designed to reflect the increasing levels of responsibility that the executive positions entail.

In late 2008, the Committee requested the compensation consultant to benchmark the Company's stock ownership guidelines to the current market. The benchmarking compared both the position levels and the multiples in our guidelines to those of the peer group and general industry designs. The benchmarking 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. To further strengthen the alignment of the interest of executives with those of our shareholders, the Board approved, on the Committee's recommendation, increasing the stock ownership for the executive officer position as shown in the table below. The stock ownership guidelines for our executive officer positions are shown in the table below:

Position Level	2008 Stock Ownership Guidelines	2009 Stock Ownership Guidelines
Chief Executive Officer	4.0 times Base Salary	5.0 times Base Salary
Chief Operating Officer	3.5 times Base Salary	4.0 times Base Salary
Chief Financial Officer	2.5 times Base Salary	3.0 times Base Salary
Presidents/Executive Vice Presidents/ Senior Vice Presidents	2.5 times Base Salary	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) performance shares/units or phantom stock deferred under an annual incentive or base salary deferral plan; (iv) performance shares/units or phantom stock earned and deferred in any long-term incentive plan account; (v) vested and unvested restricted stock awards and restricted stock units; and (vi) stock held in a family trust or immediate family holdings.

As of February 28, 2009, our named executive officers were in compliance with the guidelines (see Management Ownership table on page 7 of this Proxy Statement for specific details).

II. ELEMENTS OF COMPENSATION

The various elements of our executive compensation program described above under the caption "Compensation Program Structure" on page 18 are designed to meet the three key principles described under the caption "Compensation Philosophy and Overview" on page 16 of this Proxy Statement. We have designed an allocation of long-term to short-term compensation that reflects the job responsibilities of the executive and provides an incentive for the executive to maximize his or her contribution to the Company. 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. By comparison, Senior Vice Presidents' target long-term compensation is designed to constitute approximately one-half of their total 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[1]	Base Salary (as of 1/1/09)	Short-Term (annual) Incentive Target[2]	Long-Term Incentive Targets		Total Incentive Target
			Performance Shares[3]	Restricted Stock	
William D. Johnson	$950,000	85%	233%	117%	435%
Mark F. Mulhern	$385,000	55%	117%	58%	230%
John R. McArthur	$480,000	55%	117%	58%	230%
Jeffrey J. Lyash	$445,000	55%	117%	58%	230%
Lloyd M. Yates	$440,000	55%	117%	58%	230%

[1] Table includes only those named executive officers who were employees of the Company on January 1, 2009. (Mr. Scott retired effective September 1, 2008.)

[2] Annual incentive can range from 0%-200% of target.

[3] Performance shares may be awarded up to 125% of target and payouts 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 show the entire range of potential compensation opportunities, including the increase in the annual accrued value of the Supplemental Senior Executive Retirement Plan and a summary of compensation paid to the executive for each of the previous three years. The Committee reviews the estimated values of vested and unvested balances of accumulated long-term incentives that have been awarded to each senior executive. The Committee also uses tally sheets in adjusting annual compensation and long-term incentive awards to reflect its level of satisfaction with a particular executive's job performance.

Each of the elements of our current executive compensation program is described below.

1. BASE SALARY

The primary purposes of base salaries are to aid in attracting and retaining executives and to reward operating performance results that are consistent with reliable and efficient electric service. Base salary levels are established based on data from the utility peer group identified above and consideration of each executive officer's skills, experience, responsibilities and performance. In evaluating base salaries, the Committee also considers the fact that an individual's base salary impacts other compensation elements, including the annual incentive, long-term incentives and Supplemental Senior Executive Retirement Plan benefits, because the target amounts for each of those elements are expressed as a percentage of annual base salary earnings. 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 our primary 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 market for our 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 2008 were 6.6 percent below those of our peer group. This was primarily due to management changes that occurred in late 2007 and in 2008. While our current named executive officers have significant experience and tenure with the Company, they, as a group, have less tenure in their current positions than did our named executive officers for 2007. The positions that these newer named executive officers previously held tended to provide a lower overall compensation level than do 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 "2008 COMPENSATION DECISIONS" on page 35 below.

2. ANNUAL INCENTIVE

We sponsor the Management Incentive Compensation Plan ("MICP"), an annual cash incentive plan, in which our executives participate. 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 our peer group. For 2008, 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 specific performance levels are established based on the Company's annual goals and objectives for corporate earnings per share and business unit earnings before interest, taxes, depreciation and amortization ("EBITDA"). The specific performance targets established by the Committee for 2008 are set forth below in the section captioned "2008 COMPENSATION DECISIONS" on page 35 below. 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. The MICP's performance targets are designed to align with our financial plan and are intended to appropriately motivate the named executive officers to achieve the desired corporate financial objectives. Effective January 1, 2010, the legal entity EBITDA performance measure will be replaced by legal entity earnings.

The determination of the annual MICP award that each named executive officer receives has two steps: 1) funding the MICP awards; 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 percent 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. Effective January 1, 2008, the Company increased the number of MICP participants to include all supervisors. The supervisors were added to increase accountability for all levels of the Company's management team and to better align compensation with management performance.

For 2008, 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%	—	—
Peter M. Scott III (through August 31, 2008)	63%	100%		
Mark F. Mulhern (through August 31, 2008)[1]	45%	100%	—	—
Mark F. Mulhern (effective September 1, 2008)[1]	55%	100%	—	—
John R. McArthur (through August 31, 2008)[2]	45%	100%	—	—
John R. McArthur (effective September 1, 2008)[2]	55%	100%	—	—
Jeffrey J. Lyash	55%	45%	—	55%
Lloyd M. Yates	55%	45%	55%	—

[1] Mr. Mulhern's performance measure opportunities and relative weights under the MICP were adjusted effective September 1, 2008, to reflect his becoming the Company's Senior Vice President and Chief Financial Officer. Mr. Mulhern's MICP award for 2008 was prorated to reflect the proportion of time served in his respective roles.

[2] Mr. McArthur's performance measure opportunities and relative weights under the MICP were adjusted effective September 1, 2008, to reflect his becoming the Company's Executive Vice President. Mr. McArthur's MICP award for 2008 was prorated to reflect the proportion of time served in his respective roles.

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 performance 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. With respect to 2008, the Committee exercised discretion for the three performance measures—earnings per share, PEC EBITDA, and PEF EBITDA. The Committee adjusted earnings per share results upward by $0.01 to account for the impact of regulatory amortization. The Committee adjusted the PEC EBITDA results upward by $9 million to reflect the impact of unfavorable weather. The Committee also adjusted the PEF EBITDA upward by $22 million to reflect the impact of unfavorable weather. These adjustments resulted in earnings per share, PEC EBITDA and PEF EBITDA performance at 130 percent, 59 percent and 83 percent of target, respectively.

The Company will seek 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 EIP is intended 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. If the EIP is approved by our shareholders, the Committee will establish an unfunded incentive pool for each performance period and will allocate a specified percentage or other amount of the incentive pool for each named executive officer. The Committee may reduce the amount payable to a participant according to business factors determined by the Committee, including the performance measures under the MICP. Awards will be earned based upon the achievement of performance measures approved by the Committee.

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. Under the Equity Incentive Plan, awards may be granted in any combination of options, restricted stock, restricted stock units, performance shares or any other right or option payable in the form of stock. 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 goals. To that end, the Committee links the number of performance shares earned to the level of performance of the Company over a three-year period. 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 form of Restricted Stock Unit Agreement under the Equity Incentive Plan was amended in 2008 to allow restricted stock units that were issued to the named executive officers to vest in one-third increments in each of the first, second and third years following the grant date.

The table below shows the 2008 long-term incentive targets for each of the named executive officer's positions.

Long-Term Incentive Award Target[1]

Position[2]	Performance Shares Target Award 2008	Restricted Stock Units Target Award 2008
Chief Executive Officer	233%	117%
Executive Vice President	117%	58%
Chief Financial Officer[3]	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.

[3] Targets in the table above are those of Mr. Mulhern, our Chief Financial Officer, effective September 1, 2008. Targets for Mr. Scott, who served as our Chief Financial Officer until September 1, 2008, were set pursuant to Mr. Scott's 2005 Amended Employment Agreement and were 165% and 85% for Performance Shares and Restricted Stock Units, respectively.

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 2008 were 15% lower than those 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 "2008 COMPENSATION DECISIONS" on page 35 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 Performance Share Sub-Plan ("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 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 issued to each participant. The Committee may exercise discretion in determining the size of each performance share grant, with the maximum grant size at 125 percent of target. In 2008, 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 would be set at the beginning of each grant's 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 measures for the performance shares granted in 2008 are shown in the table below.

		Threshold	Target	Outstanding
Total Business Return*	<5%	5%	8%	11% or >
% of Target Award Earned	0%	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.

The Committee established the performance share target and outstanding measures at 8 percent and 11 percent, respectively, to reflect the financial performance that we publicly disclosed as the combined targeted growth rate for earnings per share and dividends. 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 also 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") in addition to the annual 2007 performance share grant. Transitional Grants were determined using the same Total Business Return measure as the annual grants described above.

The Transitional Grants consisted of two separate grants, with one that vested in 2008 and one that will vest 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 will be reduced by awards, if any, from the outstanding 2005 and 2006 performance share grants vesting in the same year that the Transitional Grants vest. Based on the performance results calculated under the terms of the PSSP, the Company did not make a payout in 2008 in connection with the performance shares that were issued in 2005. (Based on current relative performance expectations, the Company does not expect to make a payout in connection with the performance shares that were issued in 2006, and will vest in 2009.) Under the terms of the Transitional Grants, the actual payout opportunity ranges from 0 percent to 200 percent of the grant, based on our performance. With respect to performance shares granted after 2006, the Committee retains 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.

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 further modified to better align it with the prevailing structure of the long-term incentive plans of companies in the performance peer group we use for benchmarking compensation and to improve its alignment with the Company's goals. The 2009 PSSP includes 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 a three-year performance period and are paid out in Company common stock.

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 our peers', 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.
- Earnings growth is based on the Company's ongoing annual earnings per share (EPS). The ongoing EPS is determined in accordance with the Company's "Policy for Press Release Earnings Disclosure."

The Committee selected a highly regulated peer group for the PSSP awards comprised of highly regulated companies with a business strategy similar to ours. In addition, the 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 peer group.

Alliant Energy Corp	Great Plains	SCANA Corporation
American Electric Power Company, Inc.	NV Energy	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	Xcel Energy Inc.

This peer group differs from the peer group the Committee uses for purposes of benchmarking compensation, which is a broader group that represents those companies with which we primarily compete for executive talent. That group 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 a peer group comprised of companies that derive a significant percentage of their earnings from regulated businesses.

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. 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 20 above. The 2008 restricted stock unit targets for the named executive officer positions are shown in the "Long-Term Incentive Award Target" table on page 26 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.

The Equity Incentive Plan provides that, upon a named executive officer's retirement, the Committee may vest his restricted stock awards in its discretion. In exercising its discretion, the Committee considers many factors, such as the named executive officer's:

- assistance in the succession planning process;
- level of contribution to the Company; and
- tenure with the Company.

The Committee has not set specific criteria by which it would exercise discretion to vest retiring named executive officers' restricted stock awards units but rather considers discretionary vesting on a case-by-case basis. Discretionary vestings of restricted stock units that were approved by the Committee during 2008 are discussed in "2008 COMPENSATION DECISIONS" on page 35 below.

The Committee also may issue ad hoc grants of restricted stock units to executives in its discretion. Restrictions on ad hoc grants can be performance-based or service-based at the Committee's discretion. The Committee did not award any ad hoc grants to the named executive officers during 2008.

4. SUPPLEMENTAL SENIOR EXECUTIVE RETIREMENT PLAN

We sponsor the Supplemental Senior Executive Retirement Plan ("SERP"), which 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, 10 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 portion of total compensation similar to the portion 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. 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. Except for Mr. McArthur, 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. For those executives who were SERP participants as of December 31, 2008, the monthly SERP payment is calculated using a formula that equates to 4 percent per year of service (capped at 62 percent) 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 percent rather than 4 percent per year of service. None of the named executive officers for 2008 are 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 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 percent 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 percent 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 percent 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 percent of those directors, cease to constitute at least two-thirds (2/3) 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:

- 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 change-in-control.

Benefit	Description
Annual Incentive	100% of target bonus
Restricted Stock Agreements	Restrictions are fully removed on all outstanding grants upon termination and executive takes full and unrestricted ownership of shares
Performance Share Sub-Plan	Outstanding awards vest as of the termination date and interim calculations are made to determine payout
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 57 through 67 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 46 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 in lieu of including the costs of those benefits in the executives' base salaries. Under this approach, the costs of perquisites and other personal benefits are not considered part of base salary and therefore do not affect the calculation of awards and benefits under our various compensation arrangements (e.g., incentive compensation plans and post-employment compensation arrangements). Amounts attributable to perquisites are disclosed in the "All Other Compensation" column of the Summary Compensation Table on page 40.

During 2008, 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 took action to reduce the perquisites provided to the named executive officers. The following table shows the perquisites provided to the named executive officers during the first quarter of 2008 and notes which perquisites were discontinued effective April 1, 2008.

Perquisites for First Quarter	Status Effective April 1, 2008
Car Allowance	*Discontinued*
Country Club Membership	*Discontinued*
Nonbusiness-Related Use of Event Tickets	*Discontinued*
Tax Gross-Up Payment for Perquisites[1]	*Discontinued*
Personal Travel on Corporate Aircraft[2]	*Discontinued*
Personal Spousal Travel on Corporate Aircraft[2]	*Discontinued*
"Business-Related" Spousal Travel on Corporate Aircraft[3]	Continuing
Financial and Estate Planning	Continuing
Tax Preparation Services	Continuing
Luncheon and Health Club Dues	Continuing
Executive Physical	Continuing
Internet and Telecom Access[4]	Continuing
Home Security	Continuing
Accidental Death and Dismemberment Insurance	Continuing

[1] Executives received gross-up payments for state and federal income tax obligations related to perquisites provided during the first quarter of 2008.

[2] 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.

[3] Executives' spouses may travel on the Company's aircraft to accompany the executives to "business-related" events that executives' spouses are requested to attend. For 2008, the named executive officers whose perquisites included spousal travel for business purposes were Messrs. Johnson, Scott, McArthur, Lyash and Yates.

[4] 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 percent 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 percent of his or her salary for a minimum of five years or until his or her date of retirement. Historically, as a make-up for the 401(k) statutory compensation limits, executives also received deferred compensation credits of up to 6 percent of their base salary over the Internal Revenue Code statutory compensation limit on 401(k) retirement plans. This was accomplished through a base Company contribution of 3 percent plus an incentive contribution of up to an additional 3 percent. Beginning January 1, 2008, the Company increased the Company's base contribution to 6 percent of base salary and eliminated the incentive portion of the additional contribution. This change was made to replicate similar changes made in the Company's broad-based 401(k) plan. The Committee viewed the matching feature as a restoration benefit designed to restore the matching contribution the executive would have received if the Internal Revenue Service compensation limits remained in effect. 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 percent 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 percent 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. 2008 COMPENSATION DECISIONS

Chief Executive Officer Compensation

William D. Johnson

For 2008, the Committee recommended Mr. Johnson's salary remain at $950,000 due to the fact that in December 2007, the Committee approved increasing Mr. Johnson's salary from $790,000 as a result of his promotion to Chairman, President, and Chief Executive Officer of the Company. Mr. Johnson's base salary was established at $154,000 below the 50th percentile of the market primarily due to Mr. Johnson's short tenure in the position.

For 2008, the Committee set Mr. Johnson's MICP target award at 85 percent 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 consistent with the 50th percentile of market. The payout of the 2008 award was based on Mr. Johnson's achievement of his performance goals, which were focused on the following general areas of Company success:

- Delivering operational excellence and customer satisfaction;
- Achieving financial objectives;
- Managing construction projects effectively;
- Building support for the Company's Balanced Solution strategy;
- Achieving acceptable Levy EPC agreement and need case ruling;
- Achieving acceptable energy-efficiency regulatory treatment; and
- Excelling in internal communications, alignment, and collaboration.

Mr. Johnson's performance goals for 2008 were similar to the focus areas that he assumed when he was promoted in 2007. In recognition of his accomplishments during 2008, the Committee awarded Mr. Johnson an MICP payout of $929,000, which is equal to 115 percent of Mr. Johnson's target award.

With respect to his long-term incentive compensation during 2008, Mr. Johnson was granted 22,951 restricted stock units and 45,705 performance shares in accordance with his pre-established targets of 117 percent and 233 percent, respectively, of his base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. Additionally, 29,456 of the 58,912 transitional performance shares Mr. Johnson was granted in 2007 vested in 2008. The remaining 29,456 will vest in 2009. These transitional performance shares were granted to address the ineffectiveness of the former long-term incentive plans as described in the "Performance Shares" discussion of the "LONG-TERM INCENTIVES" section on page 26 above. The significant decrease in total year-over-year compensation to Mr. Johnson for 2008, as compared to 2007, as noted in the "Summary Compensation Table" on page 40 of this Proxy Statement, was largely due to the expensing impacts pursuant to SFAS No. 123(R) of these one-time transitional performance share grants made in 2007.

Chief Financial Officer Compensation

Peter M. Scott III

Mr. Scott served as the Chief Financial Officer in 2008 until his retirement on September 1, 2008. This discussion sets forth the 2008 compensation decisions the Committee made with respect to Mr. Scott.

For 2008, the Committee approved a base salary of $690,000 for Mr. Scott. This amount represented an increase of approximately 2.2 percent above Mr. Scott's salary for 2007 and placed his salary at $115,000 above the 50th percentile of the market for our peer group. Mr. Scott's salary increase was based on the Committee's recognition of (i) his success in leading the Company to achieve key financial goals (EPS) while sustaining earnings growth and continuing to increase the Company's annual dividend yield; and (ii) the fact that the scope of Mr. Scott's position exceeded that of a traditional CFO role because Mr. Scott also acted as President of Progress Energy Service Company LLC (the "Service Company") and served as the Company's primary administrative officer.

For 2008, the Committee awarded Mr. Scott an MICP award of $350,000, which was equal to 106 percent of his target award. Mr. Scott's 2008 MICP target percentage did not change from the previous year and was established pursuant to the 2005 amendment to his employment agreement with the Company. Mr. Scott's performance goals for 2008 were consistent with the focus areas that were established for Mr. Johnson, which are discussed above. Mr. Scott's award was due in part to his providing strong financial leadership during difficult and volatile economic times; leading efforts to reduce the Service Company operating costs; achieving our EPS goal; and maintaining strong relationships with the financial community.

With respect to his long-term compensation, in 2008, Mr. Scott was granted 11,847 restricted stock units and 22,997 performance shares in accordance with his pre-established targets of 85 percent and 165 percent, respectively, of base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. While Mr. Scott's long-term incentive targets were above the 50th percentile of market, the Committee did not adjust them in 2008 because they were contractually established pursuant to the 2005 amendment to Mr. Scott's employment agreement with the Company. Additionally, 21,693 shares of the 2007 transitional performance shares vested in 2008 and were paid out at 150% of target, and 21,693 shares for the 2007 two-year transitional performance share grant vested on September 1, 2008, per the 2005 amendment to Mr. Scott's employment agreement with the Company. (The transitional shares were granted to address the ineffectiveness of the former long-term incentive plan as described in the "Performance Shares" discussion of the "LONG-TERM INCENTIVES" section on page 26 above). The significant decrease in year-over-year total compensation to Mr. Scott for 2008, as compared to 2007, as noted in the "Summary Compensation Table" on page 40 of this Proxy Statement, was largely due to the expensing impacts pursuant to SFAS No. 123(R) of these one-time transitional performance share grants made in 2007.

Upon Mr. Scott's retirement on September 1, 2008, in accordance with terms of the 2005 amendment to his employment agreement, 20,101 shares of restricted stock vested, including 2,534 from the 2004 grant. Also, 21,693 shares from the 2007 Annual Performance Shares grant vested. In addition, 5,110 shares from the 2008 Annual PSSP grant vested, along with 14,708 Restricted Stock Units (11,690 units for 2007 per Mr. Scott's 2005 amended employment agreement and 3,018 units for the 2008 grant, calculated on a pro-rata basis).

Mark F. Mulhern

Mr. Mulhern became the Company's Chief Financial Officer on September 1, 2008. Prior to his promotion, Mr. Mulhern had served as the Senior Vice President-Finance.

In March 2008, the Committee approved a base salary of $350,000 for Mr. Mulhern, representing an increase of approximately 6.1 percent above his salary from July 1, 2007, when he became Senior Vice President – Finance. On July 3, 2008, the Committee approved a base salary of $385,000 for Mr. Mulhern (effective September 1, 2008) as a result of his promotion to Chief Financial Officer of the Company. The new base salary was set at $115,000 below the 50th percentile of the market. The Committee established Mr. Mulhern's base salary at this level due to his relatively short tenure in the Chief Financial Officer position.

For 2008, Mr. Mulhern's initial MICP target was approximately 45 percent of his base salary. Upon his promotion to Chief Financial Officer, the Committee established Mr. Mulhern's MICP target at 55 percent of base salary based on the compensation consultant's advice that this level is consistent with the 50th percentile of market. (Mr. Mulhern's effective MICP target for 2008 was approximately 48 percent of his base salary, reflecting a prorated blend of the applicable incentive target for the respective positions he held in 2008, 45 percent for the Senior Vice-President–Finance position and 55 percent for the Chief Financial Officer position.) Mr. Mulhern's performance goals for 2008 were consistent with the focus areas established for Mr. Scott as discussed above. In recognition of the achievements he accomplished in his various roles during 2008, the Committee awarded Mr. Mulhern an MICP payout of $200,000, which is equal to 116 percent of Mr. Mulhern's target award. Mr. Mulhern's award was due in part to his successful transition into the Chief Financial Officer role; achieving our EPS goal; and leading efforts to maintain positive relationships with the Board, the Finance Committee, and the financial community in a difficult and volatile economy.

With respect to his long-term incentive compensation, in 2008, Mr. Mulhern was granted 3,407 restricted stock units and 6,814 performance shares in accordance with his pre-established targets of 50 percent and 100 percent, 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 transitional performance shares vested in 2008 and were paid out at 150% of target, and 7,131 shares of the transitional performance shares will vest in 2009. The transitional "Performance Shares" are discussed in the "LONG-TERM INCENTIVES" section on page 26. The increase in year-over-year total compensation to Mr. Mulhern for 2008, as compared to 2007, as noted in the "Summary Compensation Table" on page 40 of this Proxy Statement, was largely due to Mr. Mulhern becoming vested in the SERP in 2008.

Compensation of Other Named Executive Officers

In March 2008, the Committee approved a base salary of $460,000 for Mr. McArthur, representing an increase of approximately 5.75 percent above his 2007 salary. On July 3, 2008, the Committee approved a base salary of $480,000 for Mr. McArthur, effective September 1, 2008, as a result of his promotion to Executive Vice President of the Company. The new base salary was set at $15,000 below the 50th percentile of the market. The Committee established Mr. McArthur's salary at this level due to his relatively short tenure in the Executive Vice President position.

For 2008, the Committee approved base salaries for Messrs. Lyash and Yates of $445,000 and $440,000, respectively. The base salaries for Messrs. Lyash and Yates represented an increase of approximately 11.25 and 10.00 percent, respectively, above their 2007 salaries and placed their 2008 salaries at $50,000 and $45,000 below, respectively, the 50th percentile of the market. The Committee's decision to increase Mr. Lyash's and Mr. Yates's base salaries by 11.25 percent and 10 percent, respectively, for 2008 reflected Messrs. Lyash's and Yates's strong leadership, corporate contribution and continued professional growth, while still recognizing their relatively short tenure in their current roles.

For 2008, the Committee awarded Messrs. McArthur, Lyash and Yates MICP awards as described in the table below.

Named Executive Officer	2008 MICP Award	Percent of Target	Explanation of Award
John R. McArthur	$250,000	113	Mr. McArthur was instrumental in refining and accelerating implementation of our public policy/regulatory strategy for addressing climate change, and initiating efforts to increase Service Company efficiency and productivity, which resulted in lower cost for our utilities. His achievements included initiating the Continuous Business Excellence process with a reorganized, leaner business services organization and leading the Service Company's successful efforts to exceed its productivity and O&M improvement targets.
Jeffrey J. Lyash	$225,000	95	Mr. Lyash played a significant role in leading the Levy project in meeting several major milestones, leading efforts to gain strong public and policy leader support for base-load transmission; and meeting capital and O&M budgets.
Lloyd M. Yates	$210,000	89	Mr. Yates played a significant role in leading PEC to exceed its net income goals, developing relationships with large business customers and key regulators on the state and federal level; implementing scenarios based resource planning; and implementing activity based costing with a process focus to improve efficiency and productivity.

With respect to long-term compensation, in 2008 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, as well as transitional performance share grants that the Committee issued in 2007.

Named Executive Officer	Restricted Stock Units Vesting in 1/3 Increments in 2009, 2010 and 2011	Transitional Performance Shares Vesting 2008	Transitional Performance Shares Vesting 2009	Performance Shares Vesting 2010
John R. McArthur	4,491	8,863	8,863	8,863
Jeffrey J. Lyash	4,790	9,535	9,535	9,535
Lloyd M. Yates	4,790	9,535	9,535	9,535

As described in the "Performance Shares" discussion of the "LONG-TERM INCENTIVES" section on page 26 above, the one-time grants of transitional performance shares were issued by the Committee to address the ineffectiveness of the former long-term incentive plan. The significant decrease in year-over-year total compensation to Messrs. McArthur and Lyash for 2008, as compared to 2007, as noted in the "Summary Compensation Table" on page 40 of this Proxy Statement, was largely due to the expensing impacts pursuant to SFAS No. 123(R) of the one-time transitional performance share grants for the applicable officers as set forth in the table above. The increase in year-over-year total compensation to Mr. Yates for 2008, as compared to 2007, as noted in the "Summary Compensation Table" on page 40 of this Proxy Statement, was largely due to Mr. Yates becoming vested in the SERP in 2008.

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
David L. Burner
Harris E. DeLoach, Jr.
Robert W. Jones
W. Steven 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 2008

The following Summary Compensation Table discloses the compensation of our Chief Executive Officer during 2008, both individuals who served as our Chief Financial Officer during 2008, and the other three most highly paid executive officers who were serving at the end of 2008. The values in the table reflect the compensation expense for financial statement reporting purposes in accordance with generally accepted accounting principles, in particular SFAS No. 123(R). For example, our stock option program was discontinued in 2004, but because options are expensed over the vesting period, the table reflects the remaining expense for options that vested in 2006. Similarly, performance shares are generally expensed over the applicable vesting period. 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] ($) (i)	Total ($) (j)
William D. Johnson,	2008	$950,000	N/A	$3,114,598[8]	$0	$929,000	$1,091,256[9]	$304,571[10]	$6,389,426
Chairman, President and	2007	807,539		4,827,026	0	863,500	946,938	299,445	7,744,448
Chief Executive Officer[7]	2006	711,539		1,029,242	44,790	895,000	985,266	153,133	3,818,970
Peter M. Scott III,	2008	$526,067	N/A	$706,127[11]	$0	$350,000[12]	$686,680[13]	$194,338[14]	$2,463,213
Executive Vice President	2007	663,462		4,920,006	0	600,000	916,425	338,460	7,438,353
and Chief Financial	2006	601,923		1,613,490	41,588	685,000	1,109,862	145,674	4,197,537
Officer (retired effective September 1, 2008)									
Mark F. Mulhern,	2008	$355,385	N/A	$763,504[15]	$0	$200,000	$820,419[16]	$141,354[17]	$2,280,661
Senior Vice President and	2007	308,792		1,177,508	0	190,000	34,205	116,014	1,826,519
Chief Financial Officer	2006	273,154		170,427	11,197	200,000	26,704	66,667	748,150
(as of September 1, 2008)									
John R. McArthur,	2008	$459,423	N/A	$904,815[18]	$0	$250,000	$46,028[19]	$137,536[20]	$1,797,802
Executive Vice President	2007	426,923		1,505,628	0	275,000	39,818	158,864	2,406,233
and Corporate Secretary	2006	389,616		280,815	17,568	300,000	31,935	95,794	1,115,728
(as of September 1, 2008)									
Jeffrey J. Lyash,	2008	$432,885	N/A	$905,018[21]	$0	$225,000	$323,904[22]	$140,812[23]	$2,027,619
President and Chief	2007	386,154		1,507,566	0	265,000	272,656	125,548	2,556,924
Executive Officer, PEF	2006	317,212		149,838	11,986	290,000	686,033	84,466	1,539,535
Lloyd M. Yates,	2008	$429,231	N/A	$915,801[24]	$0	$210,000	$777,983[25]	$155,042[26]	$2,488,057
President and Chief	2007	374,039		1,505,493	0	265,000	26,730	127,981	2,299,243
Executive Officer, PEC	2006	308,846		161,153	14,393	240,000	21,399	89,893	835,684

[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 2008 expense related to restricted stock and performance share awards for financial statement reporting purposes in accordance with SFAS No. 123(R). 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, 2008. The 2008 Stock Award amounts for each named executive officer are lower than the amounts reported in 2007. This reduction is related to the following: (i) a reduction in the projected payout for the 2007 2-year transitional grant from 150 percent in 2007 to 100 percent in 2008; and (ii) the payout of the 2007 1-year transitional grant, which was expensed in 2007 at 150 percent.

[3] Includes the value of stock options that were granted prior to 2006 and expensed in 2006 for financial statement reporting purposes in accordance with SFAS No. 123(R). We ceased granting stock options in 2004. No additional expense remains with respect to our stock option program, which was discontinued in 2004. All options were vested as of the end of 2006.

[4] Includes the awards given under the Management Incentive Compensation Plan for 2006, 2007 and 2008 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 SERP current incremental present value was 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 6.0% and 6.25% for calculating the accrued benefit for 2006 and 2007, respectively. For 2008, the FAS discount rate of 6.25% was used for calculating the Restoration Plan accrued benefit, and the FAS discount rate of 6.30% was used for calculating the accrued benefits under the Pension and SERP Plans. 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.

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[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; and the dollar value of the premium relating to the term portion and the present value of the premium relating to the whole life portion of the benefit to be received pursuant to the Executive Permanent Life Insurance program. The two drivers of expense under the Executive Permanent Life Insurance program are the number of years remaining until the policy splits or terminates, and the Company portion of the premium. The Executive Permanent Life Insurance program was terminated effective January 1, 2009; therefore, the table reflects a reduction in the present value of the cost of premiums paid on behalf of the named executive officers.

[7] Mr. Johnson did not receive additional compensation for his service on the Board of Directors.

[8] Includes performance share amortization of $2,109,578, consisting of $238,245 for the 2006 annual grant, $533,364 for the 2007 2-year transitional grant, $853,382 for the 2007 annual grant and $484,587 for the 2008 annual grant. Also includes restricted stock amortization of $1,005,020.

[9] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $44,835; the SERP: $1,037,536, primarily due to the increase in average monthly eligible pay over the past 36 months; and above market earnings on compensation deferred under the Deferred Compensation Plan for Key Management Employees of $8,885.

[10] Consists of (i) $19,369 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $3,364 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $44,500; (iii) $56,993 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $33,396 in gross-up payments for certain federal and state income tax obligations; (v) $163,225 in Restricted Stock/Unit Dividends; and (vi) $28,224 in perquisites consisting of the following: auto allowance, $5,008; financial/estate/tax planning, $10,000; Internet and telecom access, $3,816; and personal use of Company aircraft, $4,000. Other perquisites include luncheon club membership, health club dues, home security, tickets to sporting and cultural arts events, executive physical and AD&D insurance.

[11] Includes performance share amortization of ($358,534) consisting of ($575,268) for the 2-year transitional grant, and $216,734 for the 2008 annual grant. Negative amortization for the 2007 2-year transitional grant was due to the reversal of the portion of expenses that had been previously fully expensed at 150% and a reduction of the projected payout to 100%. Expenses for 2008 are due to a pro-rata amortization based on Mr. Scott's retirement date of September 1, 2008. Also includes restricted stock amortization of $1,064,660, of which $623,767 accounts for accelerated vestings.

[12] Pursuant to the amendment dated August 5, 2005, to Mr. Scott's employment agreement, the Committee exercised their discretion under the MICP to increase Mr. Scott's award for 2008 based upon Mr. Scott's performance, with such increase based upon a target award equal to 63% of Mr. Scott's base salary for the year. Mr. Scott's 2008 salary and target award were lower than in 2007 due to Mr. Scott's retirement on September 1, 2008.

[13] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $30,231, and the SERP: $656,449, primarily due to increase in average monthly eligible pay over the past 36 months. Mr. Scott's change in SERP decreased in 2008 due to a lower increase in average salary from 2007.

[14] Consists of (i) $15,966 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $7,974 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $110,475; (iii) $31,362 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $17,835 in gross-up payments for certain federal and state income tax obligations; (v) $95,433 in Restricted Stock/Unit Dividends; and (vi) $25,768 in perquisites consisting of the following: auto allowance, $4,362; financial/estate/tax planning, $9,919; health club dues, $3,775; home security, $4,679; and personal use of Company aircraft, $1,074. Other perquisites include luncheon club membership, Internet and telecom access, tickets to sporting and cultural arts events, executive physical and AD&D insurance. The reduction from 2007 is attributed to: (i) elimination of some executive perquisites on April 1, 2008; (ii) gross-up payments; and (iii) dividends from the restricted stock and restricted stock units that vested on September 1, 2008, and no longer paid through payroll.

[15] Includes performance share amortization of $392,827, consisting of $53,422 for the 2006 annual grant, $129,122 for the 2007 2-year transitional grant, $131,470 for the 2007 annual grant, and $78,813 for the 2008 annual grant. Also includes restricted stock amortization of $370,677.

[16] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $28,135; and the SERP: $821,581, primarily due to increase in average monthly eligible pay over the past 36 months. Mr. Mulhern became vested in the SERP on November 1, 2008, which attributed to his increase for the year. Accumulated Restoration Plan benefit of $29,297 was forfeited upon vesting in the SERP.

[17] Consists of (i) $20,593 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $1,257 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $8,547; (iii) $9,437 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $25,153 in gross-up payments for certain federal and state income tax obligations; (v) $68,686 in Restricted Stock/Unit Dividends; and (vi) $16,227 in perquisites consisting of the following: auto allowance, $3,877; financial/estate/tax planning, $8,000; and health club dues, $2,539. Other perquisites include luncheon club membership, home security, Internet and telecom access, tickets to sporting and cultural arts events, executive physical and AD&D insurance.

[18] Includes performance share amortization of $499,338, consisting of $71,564 for the 2006 annual grant, $160,484 for the 2007 2-year transitional grant, $163,401 for the 2007 annual grant, and $103,889 for the 2008 annual grant. Also includes restricted stock amortization of $405,477.

[19] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $22,131; and the Restoration Plan: $23,897, primarily due to the increase in average monthly eligible pay over the past 36 months.

[20] Consists of (i) $14,988 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $1,731 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $21,050; (iii) $18,885 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $10,426 in gross-up payments for certain federal and state income tax obligations; (v) $66,319 in Restricted Stock/Unit Dividends; and (vi) $25,186 in perquisites consisting of the following: auto allowance, $3,877; financial/estate/tax planning, $10,000; health club dues, $3,675; and personal use of Company aircraft, $2,696. Other perquisites include luncheon club membership, home security, Internet and telecom access, tickets to sporting and cultural arts events, executive physical and AD&D insurance.

[21] Includes performance share amortization of $511,618, consisting of $51,410 for the 2006 annual grant, $172,652 for the 2007 2-year transitional grant, $175,791 for the 2007 annual grant, and $111,766 for the 2008 annual grant. Also includes restricted stock amortization of $393,400.

[22] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $26,888; and the SERP: $297,016, primarily due to the increase in average monthly eligible pay over the past 36 months.

[23] Consists of (i) $19,369 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $770 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $8,884; (iii) $15,966 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $17,198 in gross-up payments for certain federal and state income tax obligations; (v) $62,470 in Restricted Stock/Unit Dividends; and (vi) $25,039 in perquisites consisting of the following: auto allowance, $4,362; financial/estate/tax planning, $10,000; health club dues, $3,185; and personal use of Company aircraft, $4,045. Other perquisites include luncheon club membership, home security, Internet and telecom access, tickets to sporting and cultural arts events, executive physical and AD&D insurance.

[24] Includes performance share amortization of $511,619, consisting of $51,410 for the 2006 annual grant, $172,652 for the 2007 2-year transitional grant, $175,791 for the 2007 annual grant, and $111,766 for the 2008 annual grant. Also includes restricted stock amortization of $404,183.

[25] Includes changes in present value of the accrued benefit during 2008 for the following plans: Progress Energy Pension Plan: $17,483; and the SERP: $789,997, primarily due to increase in average monthly eligible pay over the past 36 months. Mr. Yates became vested in the SERP on December 1, 2008, which attributed to his increase for the year. Accumulated Restoration Plan benefit of $29,498 was forfeited upon vesting in the SERP.

[26] Consists of (i) $19,875 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $982 in dollar value of premiums related to the Executive Permanent Life Insurance program based on 1 year until the policy splits or terminates and the total policy premium of $10,615; (iii) $15,819 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iv) $31,681 in gross-up payments for certain federal and state income tax obligations; (v) $64,807 in Restricted Stock/Unit Dividends; and (vi) $21,877 in perquisites consisting of the following: auto allowance, $4,362; financial/estate/tax planning, $10,000; and personal use of Company aircraft, $2,153. Other perquisites include luncheon club membership, health club dues, home security, Internet and telecom access, tickets to sporting and cultural arts events, executive physical and AD&D insurance.

GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]						
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units[3] (#) (i)	All Other Option Awards: Number of Securities Underlying Options[4] (#) (j)	Exercise or Base Price of Option Awards[4] (#) (k)	Grant Date Fair Value of Stock and Option Awards[5] ($) (l)
William D. Johnson, Chairman, President and Chief Executive Officer	MICP 3/6/09	$403,750	$807,500	$1,615,000							
	Restricted Stock Units 3/18/08							22,951			$973,352
	PSSP 3/18/08				22,853	45,705	91,410				$1,938,349
Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired effective September 1, 2008)	MICP 3/6/09	$165,711	$331,422	$662,844							
	Restricted Stock Units 3/18/08							11,847			$502,431
	PSSP 3/18/08				11,499	22,997	45,994				$975,303
Mark F. Mulhern, Senior Vice President and Chief Financial Officer (as of September 1, 2008)	MICP 3/6/09	$85,885	$171,769	$343,338							
	Restricted Stock Units 3/18/08							3,407			$144,491
	PSSP 3/18/08				3,407	6,814	13,628				$288,982
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	MICP 3/6/09	$111,028	$222,055	$444,110							
	Restricted Stock Units 3/18/08							4,491			$190,463
	PSSP 3/18/08				4,491	8,982	17,964				$380,927
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	MICP 3/6/09	$119,044	$238,087	$476,174							
	Restricted Stock Units 3/18/08							4,790			$203,144
	PSSP 3/18/08				4,832	9,663	19,326				$409,808
Lloyd M. Yates, President and Chief Executive Officer, PEC	MICP 3/6/09	$118,039	$236,077	$472,154							
	Restricted Stock Units 3/18/08							4,790			$203,144
	PSSP 3/18/08				4,832	9,663	19,326				$409,808

[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 2008 eligible earnings times the executive's target percentage. See target percentage in table on page 24 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 2008 PSSP grants. The grant size was calculated by multiplying the executive's salary as of January 1, 2008, times his 2008 PSSP target and dividing by the December 31, 2007, closing stock price of $48.43. 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 2008 under the 2007 Equity Incentive Plan. The number of shares granted was determined by multiplying the executive's salary as of January 1, 2008, times his 2008 restricted stock target and dividing by the December 31, 2007, closing stock price of $48.43.

[4] We ceased granting stock options in 2004.

[5] Reflects the grant date fair value of the award based on the following assumptions: Market value of restricted stock granted on March 18, 2008, based on closing price of $42.41 per share, times the shares granted in column (i). Market value of PSSP granted on March 18, 2008, based on closing stock price on March 18, 2008, of $42.41 times target number of shares in column (g).

DISCUSSION OF SUMMARY COMPENSATION TABLE AND GRANTS OF PLAN-BASED AWARDS TABLE

EMPLOYMENT AGREEMENTS

Messrs. Johnson, Scott, Mulhern, McArthur, Lyash and Yates 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, except that, with respect to Mr. Scott, the Amendment to the Employment Agreement dated August 5, 2005, remained in force in accordance with its terms until Mr. Scott retired, effective September 1, 2008. Please see below for more information regarding these two agreements.

The employment agreements provide for base salary, bonuses, perquisites and participation in the various executive compensation plans offered to our senior executives. The agreements expire 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. The employment agreements each contain 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 Messrs. Johnson and Scott, the Employment Agreements specify that the years of service credit we previously granted to them 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. Three of those years also were deemed to have been in service on the Senior Management Committee for purposes of SERP eligibility. Mr. Scott has been awarded seven years of deemed service toward the benefits and vesting requirements of the SERP.

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.

Agreement with Mr. Scott

In March 2005, Mr. Scott was assigned increased responsibilities within our Company. In light of those increased responsibilities and in order to retain Mr. Scott through at least April 1, 2008, the Organization and Compensation Committee of the Company's Board of Directors (the "Committee") approved an amendment to Mr. Scott's employment agreement (the "Amendment") on July 12, 2005. The Amendment provides for certain increases in Mr. Scott's 2005 long- and short-term compensation targets. Mr. Scott's new annual targets for long-term compensation in the form of performance share awards granted pursuant to the Performance Share Sub-Plan ("PSSP") of our 2002 Equity Incentive Plan and restricted stock increased to 165 percent and 85 percent, respectively, of his base salary for each of the years 2005, 2006 and 2007. Additionally, the Amendment provides that at the time of each annual review of MICP awards for the years 2005, 2006 and 2007, we will consider exercising discretion under the MICP to increase the awards to Mr. Scott and that any such increase will be based upon a target award equal to 63 percent of Mr. Scott's base salary for the year. Mr. Scott's base salary for 2005 was $525,000. The Amendment also provides that if (i) prior to April 1, 2008, we terminate Mr. Scott's employment without cause, or (ii) after April 1, 2008, either we terminate Mr. Scott's employment without cause, or Mr. Scott voluntarily terminates his employment, then Mr. Scott's PSSP grants for the 2006 and 2007 plan years will vest immediately upon his employment termination date, and any restricted stock awards granted to Mr. Scott in 2005, 2006 and 2007 will vest immediately upon his employment termination date. The Committee has interpreted the Amendment to apply to the 2007 restricted stock unit grant to Mr. Scott since the Company began issuing restricted stock units in lieu of restricted stock in 2007. Additionally, the Amendment provides that in lieu of accelerating the vesting schedules of the above-referenced awards, we may provide Mr. Scott with the cash value of such PSSP grants and/or restricted stock awards as of his employment termination date. The Amendment also provides that the accelerated vesting terms outlined above will not apply in the event of a constructive termination of Mr. Scott's employment.

Both the May 8, 2007 Employment Agreement with Mr. Scott and the Amendment to that Agreement terminated upon Mr. Scott's retirement from the Company, effective September 1, 2008. See "2008 COMPENSATION DECISIONS" for a discussion of the amounts Mr. Scott received upon his retirement.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

Name (a)	Option Awards[1]					Stock Awards			
	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	68,893[5]	$2,745,386	112,645[6]	$4,488,903
Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired effective September 1, 2008)	0 0 52,000	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	0[7]	$0	0[8]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer (as of September 1, 2008)	0 7,000	—	—	$41.97 $44.75	9/30/2012 9/30/2013	28,773[9]	$1,146,604	22,826[10]	$909,616
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	0 0 0	—	—	$43.80 $41.97 $44.75	1/31/2012 9/30/2012 9/30/2013	27,090[11]	$1,079,537	28,907[12]	$1,151,944
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	25,817[13]	$1,028,807	31,099[14]	$1,239,295
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	27,017[15]	$1,076,627	31,099[16]	$1,239,295

[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, 2008, was based on a December 31, 2008, closing price of $39.85 per share.

[4] Performance share value based on expected payout of 0% on outstanding 2006 PSSP grant. Performance share value for the 2007 2-year transitional grant, 2007 annual grant, and 2008 annual grant was expected to be 100% of target. The 2005 and 2007 1-year transitional grants vested on January 1, 2008; the 2006 and 2007 2-year transitional grants vested on January 1, 2009; the 2007 grant vests on January 1, 2010; and the 2008 grant vests on January 1, 2011. Expected payout for 2006 performance share grants is 0% based on total shareholder return performance as of December 31, 2008, and EBITDA performance as of September 30, 2008. The value in Column (j) is derived by multiplying the shares (rounded to the nearest whole share) times the December 31, 2008 closing stock price ($39.85). 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, 2009; 5,067 shares on March 15, 2009; 4,400 shares on March 16, 2009; 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: 7,650 units on March 18, 2009; 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, and accumulated dividends as of December 31, 2008. The 2006 performance share balances (34,379), original grant plus accumulated dividends, are excluded based on their expected payout of 0%. Outstanding performance share balances consist of the following: (i) 32,430 – 2007 2-year transitional grant; (ii) 32,430 – 2007 annual grant; and (iii) 47,785 – 2008 annual grant.

[7] Upon Mr. Scott's retirement on September 1, 2008, the vesting of restricted stock and restricted stock units was accelerated. Refer to "2008 COMPENSATION DECISIONS" in CD&A.

[8] Upon Mr. Scott's retirement on September 1, 2008, all unvested performance shares vested in accordance with the plan.

[9] Restricted stock grants vest based on the following schedule: 1,166 shares on March 14, 2009; 7,800 shares on April 28, 2009; 1,167 shares on March 14, 2010; 3,500 shares on March 21, 2010; 1,167 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 1,135 units on March 18, 2009; 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.

[10] Includes performance shares granted on March 20, 2007, March 18, 2008, and accumulated dividends as of December 31, 2008. The 2006 performance share balances (7,709), original grant plus accumulated dividends, are excluded based on their expected payout of 0%. Outstanding performance share balances consist of the following: (i) 7,851 – 2007 2-year transitional grant; (ii) 7,851 – 2007 annual grant; and (iii) 7,124 – 2008 annual grant.

[11] Restricted stock grants vest based on the following schedule: 1,666 shares on March 14, 2009; 1,433 shares on March 15, 2009; 1,300 shares on March 16, 2009; 1,667 shares on March 14, 2010; 1,434 shares on March 15, 2010; 1,667 shares on March 14, 2011. Restricted stock units grants vest based on the following schedule: 1,497 units on March 18, 2009; 1,497 units on March 18, 2010; 10,477 units on March 20, 2010; 1,497 units on March 18, 2011; 1,477 units on March 20, 2011; and 1,478 units on March 20, 2012.

[12] Includes performance shares granted on March 20, 2007, March 18, 2008, and accumulated dividends as of December 31, 2008. The 2006 performance share balances (10,327), original grant plus accumulated dividends, are excluded based on their expected payout of 0%. Outstanding performance share balances consist of the following: (i) 9,758 – 2007 2-year transitional grant; (ii) 9,758 – 2007 annual grant; and (iii) 9,391 – 2008 annual grant.

[13] Restricted stock grants vest based on the following schedule: 1,366 shares on March 14, 2009; 1,100 on March 15, 2009; 1,000 shares on March 16, 2009; 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: 1,596 units on March 18, 2009; 1,597 on March 18, 2010, 10,576 units on March 20, 2010; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; and 1,575 units on March 20, 2012.

[14] Includes performance shares granted on March 20, 2007, March 18, 2008, and accumulated dividends as of December 31, 2008. The 2006 performance share balances (7,419), original grant plus accumulated dividends, are excluded based on their expected payout of 0%. Outstanding performance share balances consist of the following: (i) 10,498 – 2007 2-year transitional grant; (ii) 10,498 – 2007 annual grant; and (iii) 10,103 – 2008 annual grant.

[15] Restricted stock grants vest based on the following schedule: 2,200 shares on March 7, 2009; 1,366 shares on March 14, 2009; 1,100 shares on March 15, 2009; 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: 1,596 units on March 18, 2009; 1,597 on March 18, 2010; 10,576 units on March 20, 2010; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; and 1,575 units on March 20, 2012.

[16] Includes performance shares granted on March 20, 2007, March 18, 2008, and accumulated dividends as of December 31, 2008. The 2006 performance share balances (7,419), original grant plus accumulated dividends, are excluded based on their expected payout of 0%. Outstanding performance share balances consist of the following: (i) 10,498 – 2007 2-year transitional grant; (ii) 10,498 – 2007 annual grant; and (iii) 10,103 – 2008 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	0		59,394[2]	$2,801,636
Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired effective September 1, 2008)	0		92,054[3]	$4,172,053
Mark F. Mulhern, Senior Vice President and Chief Financial Officer (as of September 1, 2008)	0		11,264[4]	$545,516
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	0		17,967[5]	$846,944
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	0		18,162[6]	$861,433
Lloyd M. Yates, President and Chief Executive Officer, PEC	0		17,162[7]	$818,633

[1] Reflects the number of restricted stock shares, restricted stock units, and performance shares that vested in 2008. Unless otherwise stated, no restricted stock units vested for named executive officers during 2008 and performance shares vested on January 1, 2008 for the 2005 and 2007 1-year transitional grants at $48.43 per share Restricted stock shares vested on the following days: (i) March 15th and 16th at $42.80 per share; (ii) March 18th at $42.10 per share; (iii) April 1st at $42.08 per share; and (iv) September 1st at $44.24 per share. The value realized is the sum of the vested shares for each vesting date times the vesting price.

[2] Includes 12,866 restricted stock awards consisting of the following: 5,066 on March 15th; 4,400 on March 16th; and 3,400 on March 18th. Performance shares totaled 46,528.

[3] Includes 21,400 restricted stock awards consisting of the following: 2,733 on March 15th; 2,533 on March 16th; 3,134 on March 18th; and 13,000 on April 1st. Additionally, per the August 2005 amendment to his employment agreement, Mr. Scott's remaining unvested restricted stock (20,101) and restricted stock units (14,708) vested upon his retirement on September 1, 2008. Performance shares totaled 35,845.

[4] Includes performance shares of 11,264. Mr. Mulhern did not have any restricted stock awards that vested during 2008.

[5] Includes 3,967 restricted stock awards consisting of the following: 1,433 on March 15th; 1,300 on March 16th; and 1,234 on March 18th. Performance shares totaled 14,000.

[6] Includes 3,100 restricted stock awards consisting of the following: 1,100 on March 15th; 1,000 on March 16th; and 1,000 on March 18th. Performance shares totaled 15,062.

[7] Includes 2,100 restricted stock awards consisting of the following: 1,100 on March 15th; and 1,000 on March 18th. Performance shares totaled 15,062.

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	16.3	$382,841	$0
	Supplemental Senior Executive Retirement Plan	23.3[2]	$6,213,810[3]	$0
Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired effective September 1, 2008)	Progress Energy Pension Plan	10.0	$207,825	$234,658
	Supplemental Senior Executive Retirement Plan	17.0[4]	$5,882,984[5]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer (as of September 1, 2008)	Progress Energy Pension Plan	12.8	$222,763	$0
	Restoration Retirement Plan	—	($29,297)[6]	
	Supplemental Senior Executive Retirement Plan	12.8	$821,581[7]	$0
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	Progress Energy Pension Plan	7.1	$116,596	$0
	Restoration Retirement Plan	7.1	$82,897	$0
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	Progress Energy Pension Plan	15.6	$226,167	$0
	Supplemental Senior Executive Retirement Plan	15.6	$1,223,089[8]	$0
Lloyd M. Yates, President and Chief Executive Officer, PEC	Progress Energy Pension Plan	10.1	$124,502	$0
	Restoration Retirement Plan	—	($29,498)[9]	
	Supplemental Senior Executive Retirement Plan	10.1	$789,997[10]	$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, 2008, for computation of accumulated benefit under the Supplemental Senior Executive Retirement Plan and the Progress Energy Pension Plan was 6.30%. 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. Without these seven years, Mr. Johnson's benefit multiplier was reduced in prior years under the plan. As of 2008, Mr. Johnson's benefit multiplier is not reduced without the deemed years of service, and his benefit augmentation for deemed service is $0.

[3] Based on an estimated annual benefit payable at age 65 of $980,525.

[4] Includes seven years of deemed service. As of 2008, Mr. Scott met the minimum 10 years of service required for vesting in the Supplemental Executive Retirement Plan. However, without these seven years, Mr. Scott's benefit multiplier is reduced from 62.0% to 40.05% under the plan. Therefore, his benefit augmentation for deemed years of service is $2,230,850.

[5] Based on an estimated annual benefit payable at age 65 of $727,052.

[6] Mr. Mulhern's Restoration Retirement Plan benefits were forfeited upon his vesting in the

"Supplemental Senior Executive Retirement Plan" on November 1, 2008.

[7] Based on an estimated annual benefit payable at age 65 of $187,047.

[8] Based on estimated annual benefit payable at age 65 of $314,648.

[9] Mr. Yates's Restoration Retirement Plan benefits were forfeited upon his vesting in the Senior Supplemental Retirement Plan on December 1, 2008.

[10] Based on estimated annual benefit payable at age 65 of $191,187.

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 34 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	$56,993	($51,990)[5]	$0	$616,137[6]
Peter M. Scott III, Executive Vice President and Chief Financial Officer	$0	$31,362	($70,158)	($85,394)[7]	$575,890[8]
Mark F. Mulhern, Senior Vice President and Chief Financial Officer (as of September 1, 2008)	$17,769	$9,437	($49,965)	($54,511)[9]	$297,763[10]
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	$22,971	$18,885	($2,797)	$0	$71,838[11]
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	$0	$15,966	($26,995)	$0	$91,614[12]
Lloyd M. Yates, President and Chief Executive Officer, PEC	$42,923	$15,819	($79,949)	$0	$427,147[13]

[1] Reflects salary deferred under the Management Deferred Compensation Plan, which is reported as "Salary" in the Summary Compensation Table. For 2008, named executive officers deferred the following percentages of their base salary: (i) Mulhern – 5%; (ii) McArthur – 5%; and (iii) Yates – 10%.

[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, 2008 balances under the following deferred compensation plans: Management Incentive Compensation Plan, Performance Share Sub-Plan, Management Deferred Compensation Plan, Deferred Compensation Plan for Key Management Employees.

[5] Includes above market earnings of $8,885 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: $322,440; Management Incentive Compensation Plan: $62,880, and Deferred Compensation Plan for Key Management Employees: $230,816

[7] Mr. Scott received a lump sum distribution of the Company match contributions for 2000 – 2004 and the 401(k) rollover balance under the Management Deferred Compensation Plan.

[8] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $87,327; and Performance Share Sub-Plan: $488,563.

[9] Mr. Mulhern received distributions from his Management Incentive Deferred Compensation Plan: $17,954; Management Deferred Compensation Plan: $11,944; and Performance Share Sub-Plan: $24,613.

[10] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $30,530; Management Incentive Deferred Compensation Plan: $166,552; and Performance Share Sub-Plan: $100,681.

[11] Includes balance under the Management Deferred Compensation Plan: $71,838.

[12] Includes balance under the Management Deferred Compensation Plan: $91,614.

[13] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $94,692; Management Incentive Compensation Plan: $98,195; and Performance Share Sub-Plan: $234,259.

CASH COMPENSATION AND VALUE OF VESTING EQUITY TABLE

The following table shows the actual cash compensation and value of vesting equity received in 2008 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 as shown in the Summary Compensation Table.

Name and Position	Base Salary (a)[1]	Annual Incentive (paid in 2008) (b)[2]	Deferred Salary under MDCP (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	$950.000	$863.500	$0	$548.285	$2.253.351	$163.225	$0	$28.224	$33.396	$4.839.981
Peter M. Scott III, Executive Vice President and Chief Financial Officer (retired September 1, 2008)	$526.067	$600.000	$0	$2.436.080[10]	$1.735.973	$95.433	$0	$25.768	$17.835	$5.437.156
Mark F. Mulhern, Senior Vice President & Chief Financial Officer (as of September 1, 2008)	$355.385	$190.000	$17.769	$0	$545.516	$68.686	$0	$16.227	$25.153	$1.200.967
John R. McArthur, Executive Vice President and Corporate Secretary (as of September 1, 2008)	$459.423	$275.000	$22.971	$168.924	$678.020	$66.319	$0	$25.186	$10.426	$1.683.298
Jeffrey J. Lyash, President and Chief Executive Officer, PEF	$432.885	$265.000	$0	$131.980	$729.453	$62.470	$0	$25.039	$17.198	$1.664.025
Lloyd M. Yates, President and Chief Executive Officer, PEC	$429.231	$265.000	$42.923	$89.180	$729.453	$64.807	$0	$21.877	$31.681	$1.631.229

[1] Consists of the total 2008 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 (Non-Equity Incentive* Compensation) attributable to Plan Year 2007 and paid in 2008.

[3] Consists of amounts deferred under the Management Deferred Compensation Plan (MDCP). These deferral amounts are part of Base Salary and therefore are not included in the total column.

[4] Reflects the value of restricted stock and restricted stock units vesting in 2008. 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, 2008 at $48.43 for the 2007 1-year transitional grant under the applicable PSSP.

[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 2008. Since we ceased granting stock options under our Incentive Plans in 2004, all outstanding options had fully vested in 2008.

[8] Reflects the value of all perquisites provided during 2008. For a complete listing of the perquisites, see the "Executive Perquisites" section of the "Elements of Compensation" discussion of the CD&A on page 33 of this Proxy Statement. Perquisite details for each named executive officer are discussed in the Summary Compensation Table footnotes. The value reflected does not include tax gross-ups paid relating to perquisites provided.

[9] Reflects the value of tax gross-up related to perquisites and miscellaneous income items (Supplemental Senior Executive Retirement Plan (SERP) or Restoration and MDCP 401(k) make-up) provided during 2008.

[10] Pursuant to the August 2005 amendment to his employment agreement, Mr. Scott's outstanding restricted stock awards vested upon his retirement on September 1, 2008. The vesting price was $44.24 based on the September 2, 2008 opening price. In addition, Mr. Scott's 2007 Restricted Stock Unit vested and a pro-rata portion of his 2008 Restricted Stock Unit grant vested. The vesting price was $43.68 based on the August 31, 2008 closing price.

POTENTIAL PAYMENTS UPON TERMINATION

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

	Voluntary Termination ($)	Early Retirement[13] ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$950,000 [1]	$0	$0	$0	$2,840,500	$0	$5,288,500	$0
Annual Incentive [2]	$0	$0	$0	$0	$0	$807,500	$929,000
Long-term Incentives							
Performance Shares (PSSP)							
2006 (performance period)[3]	$0	$0	$0	$0	$0	$0	$0
2007 2-yr Transitional Grant [4]	$0	$0	$0	$0	$0	$1,292,336	$1,292,336
2007 (performance period) [4]	$0	$0	$0	$0	$0	$1,292,336	$1,292,336
2008 (performance period) [4]	$0	$0	$0	$0	$0	$1,904,232	$634,744
Restricted Stock Units [5]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$196,700	$196,700
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$196,700	$196,700
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$196,700	$196,700
2008 – 2009 (grant date vesting)	$0	$0	$0	$0	$0	$304,853	$0
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$304,853	$0
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$304,892	$0
Restricted Stock [6]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$1,240,690	$1,240,690
Benefits and Perquisites							
Incremental Non-Qualified Pension [7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation [8]	$616,137	$0	$0	$616,137	$616,137	$616,137	$616,137
Post-retirement Health Care [9]	$0	$0	$0	$22,936	$0	$44,972	$0
Split-Dollar Policy [10]	$150,914	$0	$0	$150,914	$150,914	$133,500	$1,140,938
Executive AD&D Proceeds [11]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up [12]	$0	$0	$0	$0	$0	$4,263,228	$0
TOTAL	**$767,051**	**$0**	**$0**	**$3,630,487**	**$767,051**	**$18,388,125**	**$8,235,739**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below). 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 ($950,000) 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 (($950,000 + $812,833) 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.

[2] 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 early retirement or normal retirement (see footnote 13 below). In the event of involuntary or good reason termination (CIC), Mr. Johnson would receive 100% of his target bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 85% times $950,000. In the event of death or disability, Mr. Johnson would receive a pro-rata incentive award for the period worked during the year. For December 31, 2008, this is based on the full award. For 2008, Mr. Johnson's MICP award was $929,000.

[3] For the 2006 performance shares grant, the expected payout as of December 31, 2008 was 0%.

[4] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below). 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, 2008, the performance factor is 100%. In the event of death or disability, the 2007 2-year transitional and 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 performance grant, a pro-rata payment would be made based upon time in the plan.

[5] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below). 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, and would forfeit 22,951 restricted stock units granted on March 18, 2008.

[6] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below). 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 31,134 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, 2008, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[8] 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. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below). 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. Mr. Johnson is not eligible for early retirement or normal retirement (see footnote 13 below.) Under involuntary not for cause termination, Mr. Johnson would be reimbursed for 18 months of COBRA premiums at $1,274.20 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 $1,249.22 per month.

[10] The Executive Permanent Split-Dollar Life Insurance program involves sharing of insurance costs and benefits between the Company and the participant. The benefit sharing was scheduled to end at age 65. However, in 2008 the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. Mr. Johnson surrendered his policy for cash value. Surrender proceeds were issued in January 2009 equal to the greater of the 2008 projected cash surrender value per the original policy illustration or actual cash value at December 31, 2008, with a minimum of $5,000. At December 31, 2008, the program was still active and potential payments would have been due under the following events: Under voluntary termination, involuntary not for cause termination, and for cause termination, the policy would be split in proportion to cash value ownership. The amounts in these columns represent the 2008 projected cash surrender value per the original policy illustration. There is no provision for early retirement under the Split-Dollar program, and Mr. Johnson is not eligible for normal retirement. Under involuntary or good reason termination (CIC), this value represents premiums that would be paid by the Company for three years. In the event of death, proceeds of the Policy would be payable as of the last policy anniversary date.

[11] Mr. Johnson would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[12] 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 $7,861,968 of excess parachute payments above his base amount. Those excess parachute payments result in $1,572,394 of excise taxes, $2,629,901 of tax gross-ups, and $60,933 of employer Medicare tax related to the excise tax payment.

[13] Mr. Johnson was not eligible for early retirement at December 31, 2008. However, he became eligible at age 55 on January 9, 2009. A description of his potential payments in the event of early retirement follows. A pro-rata incentive award for the period worked during the year. (At December 31, 2008, this is based on the full award of $929,000.) Performance shares would vest 100 percent for the 2007 2-year transitional and 2007 performance grants, and on a pro-rata basis for the 2008 performance grant based upon the plan: $1,292,336; $1,292,336; and $634,744, respectively. The six restricted stock units (RSU) grants above would vest on a pro-rata basis based on time in the plan: $114,728; $86,076; $68,861; $228,659; $114,330; $76,233. Restricted stock would vest at the Committee's discretion, potentially 100 percent, which equates to $1,240,690 at December 31, 2008. All outstanding deferred compensation balances would be paid in accordance with the plan and participant elections, subject to IRC Section 409(a) regulations: $616,130. There is no provision for additional benefits upon early retirement in any of the other plans in the table above.

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—$385,000 [1]	$0	$0	$0	$1,151,150	$0	$1,193,500	$0
Annual Incentive [2]	$0	$0	$0	$0	$0	$211,750	$200,000
Long-term Incentives							
Performance Shares (PSSP)							
2006 (performance period) [3]	$0	$0	$0	$0	$0	$0	$0
2007 2-yr Transitional Grant [4]	$0	$0	$0	$0	$0	$312,862	$312,862
2007 (performance period) [4]	$0	$0	$0	$0	$0	$312,862	$312,862
2008 (performance period) [4]	$0	$0	$0	$0	$0	$283,891	$77,425
Restricted Stock Units [5]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$47,382	$47,382
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$47,382	$47,382
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$47,342	$47,342
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$278,950	$278,950
2008 – 2009 (grant date vesting)	$0	$0	$0	$0	$0	$45,230	$0
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$45,270	$0
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$45,270	$0
Restricted Stock [6]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$589,780	$589,780
Benefits and Perquisites							
Incremental Non Qualified Pension [7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation [8]	$297,763	$0	$0	$297,763	$297,763	$297,763	$297,763
Post-retirement Health Care [9]	$0	$0	$0	$16,205	$0	$21,183	$0
Split-Dollar Policy [10]	$40,487	$0	$0	$40,487	$40,487	$17,094	$754,260
Executive AD&D Proceeds [11]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up [12]	$0	$0	$0	$0	$0	$976,637	$0
TOTAL	**$338,250**	**$0**	**$0**	**$1,505,605**	**$338,250**	**$4,774,147**	**$3,466,007**

[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 ($385,000) 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 (($385,000 + $211,750) 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 bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $385,000. 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, 2008, this is based on the full award. For 2008, Mr. Mulhern's MICP award was $200,000.

[3] For the 2006 performance shares grant, the expected payout as of December 31, 2008 was 0%.

[4] 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, 2008, the performance factor is 100%. In the event of death or disability, the 2007 2-year transitional and 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 performance grant, a pro-rata payment would be made based upon time in the plan.

[5] 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, and would forfeit 3,407 restricted stock units granted on March 18, 2008.

[6] 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 14,800 restricted stock shares would vest immediately.

[7] 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, 2008, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[8] 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.

[9] 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 $900.29 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 $882.64 per month.

[10] The Executive Permanent Split-Dollar Life Insurance program involves sharing of insurance costs and benefits between the Company and the participant. The benefit sharing was scheduled to end at age 65. However, in 2008, the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. Mr. Mulhern surrendered his policy for cash value. Surrender proceeds were issued in January 2009 equal to the greater of the 2008 projected cash surrender value per the original policy illustration or actual cash value at December 31, 2008, with a minimum of $5,000. At December 31, 2008, the program was still active and potential payments would have been due under the following events: Under voluntary termination, involuntary not for cause termination, and for cause termination, the policy would be split in proportion to cash value ownership. The amounts in these columns represent the actual cash value at December 31, 2008. There is no provision for early retirement under the Split-Dollar program, and Mr. Mulhern is not eligible for normal retirement. Under involuntary or good reason termination (CIC), this value represents premiums that would be paid by the Company for two years. In the event of death, proceeds of the Policy would be payable as of the last policy anniversary date.

[11] Mr. Mulhern would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[12] 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 $1,801,050 of excess parachute payments above his base amount. Those excess parachute payments result in $360,210 of excise taxes, $602,468 of tax gross-ups, and $13,959 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
John R. McArthur, Executive Vice President

	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—$480,000 [1]	$0	$0	$0	$1,435,200	$0	$2,260,000	$0
Annual Incentive [2]	$0	$0	$0	$0	$0	$264,000	$250,000
Long-term Incentives							
Performance Shares (PSSP)							
2006 (performance period) [3]	$0	$0	$0	$0	$0	$0	$0
2007 2-yr Transitional Grant [4]	$0	$0	$0	$0	$0	$388,856	$388,856
2007 (performance period) [4]	$0	$0	$0	$0	$0	$388,856	$388,856
2008 (performance period) [4]	$0	$0	$0	$0	$0	$374,231	$102,063
Restricted Stock Units [5]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$58,858	$58,858
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$58,858	$58,858
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$58,898	$58,898
2007 Retention Grant (grant date vesting)	$0	$0	$0	$0	$0	$358,650	$358,650
2008-2009 (grant date vesting)	$0	$0	$0	$0	$0	$59,655	$0
2008-2010 (grant date vesting)	$0	$0	$0	$0	$0	$59,655	$0
2008-2011 (grant date vesting)	$0	$0	$0	$0	$0	$59,655	$0
Restricted Stock [6]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$365,305	$365,305
Benefits and Perquisites							
Incremental Non Qualified Pension [7]	$0	$0	$0	$0	$0	$1,225,262	$0
Deferred Compensation [8]	$71,838	$0	$0	$71,838	$71,838	$71,838	$71,838
Post-retirement Health Care [9]	$0	$0	$0	$22,494	$0	$44,105	$0
Split-Dollar Policy [10]	$5,000	$0	$0	$5,000	$5,000	$63,149	$789,383
Executive AD&D Proceeds [11]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up [12]	$0	$0	$0	$0	$0	$2,162,892	$0
TOTAL	**$76,838**	**$0**	**$0**	**$1,534,532**	**$76,838**	**$8,322,727**	**$3,391,567**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. McArthur is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. McArthur's employment agreement requires a severance equal to 2.99 times his then current base salary ($480,000) 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 (($480,000 + $273,333) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. McArthur 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. McArthur is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. McArthur would receive 100% of his target bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $480,000. In the event of death or disability, Mr. McArthur would receive a pro-rata incentive award for the period worked during the year. For December 31, 2008, this is based on the full award. For 2008, Mr. McArthur's MICP award was $250,000.

[3] For the 2006 performance shares grant, the expected payout as of December 31, 2008 was 0%.

[4] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. McArthur 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, 2008, the performance factor is 100%. In the event of death or disability, the 2007 2-year transitional and 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 performance grant, a pro-rata payment would be made based upon time in the plan.

[5] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. McArthur 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. McArthur would immediately vest 13,432 restricted stock units granted on March 20, 2007, and would forfeit 4,491 restricted stock units granted on March 18, 2008.

[6] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. McArthur 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. McArthur's restricted stock grant dates are beyond the one-year threshold; therefore, all 9,167 restricted stock shares would vest immediately.

[7] Mr. McArthur was not vested under the SERP as of December 31, 2008, so this is the incremental value due to accelerated vesting under involuntary or good reason termination (CIC). No accelerated vesting or incremental nonqualified pension benefit applies under any other scenario above.

[8] 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. McArthur is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Mr. McArthur 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. Mr. McArthur is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. McArthur would be reimbursed for 18 months of COBRA premiums at $1,249.64 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. McArthur was participating in prior to termination for 36 months at $1,225.14 per month.

[10] The Executive Permanent Split-Dollar Life Insurance program involves sharing of insurance costs and benefits between the Company and the participant. The benefit sharing was scheduled to end at age 65. However, in 2008, the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. Mr. McArthur surrendered his policy for cash value. Surrender proceeds were issued in January 2009 equal to the greater of the 2008 projected cash surrender value per the original policy illustration or actual cash value at December 31, 2008, with a minimum of $5,000. At December 31, 2008, the program was still active and potential payments would have been due under the following events: Under voluntary termination, involuntary not for cause termination, and for cause termination, the policy would be split in proportion to cash value ownership. The amounts in these columns represent the 2008 projected cash surrender value per the original policy illustration with a minimum of $5,000. There is no provision for early retirement under the Split-Dollar program, and Mr. McArthur is not eligible for normal retirement. Under involuntary or good reason termination (CIC), this value represents premiums that would be paid by the Company for three years. In the event of death, proceeds of the Policy would be payable as of the last policy anniversary date.

[11] Mr. McArthur would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[12] 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. McArthur. Under IRC Section 280G, Mr. McArthur would be subject to excise tax on $3,988,664 of excess parachute payments above his base amount. Those excess parachute payments result in $797,733 of excise taxes, $1,334,245 of tax gross-ups, and $30,914 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Jeffrey J. Lyash, President and Chief Executive Officer, PEF

	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—$445,000 [1]	$0	$0	$0	$1,330,550	$0	$2,070,000	$0
Annual Incentive [2]	$0	$0	$0	$0	$0	$244,750	$225,000
Long-term Incentives							
Performance Shares (PSSP)							
~~2006 (performance period) [3]~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~
2007 2-yr Transitional Grant [4]	$0	$0	$0	$0	$0	$418,345	$418,345
2007 (performance period) [4]	$0	$0	$0	$0	$0	$418,345	$418,345
2008 (performance period) [4]	$0	$0	$0	$0	$0	$402,605	$109,801
Restricted Stock Units [5]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$62,804	$62,804
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$62,804	$62,804
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$62,764	$62,764
2007 Retention Grant (grant date vesting)	$0	$0	$0	$0	$0	$358,650	$358,650
2008 – 2009 (grant date vesting)	$0	$0	$0	$0	$0	$63,601	$0
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$63,640	$0
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$63,640	$0
Restricted Stock [6]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$290,905	$290,905
Benefits and Perquisites							
Incremental Non-Qualified Pension [7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation [8]	$91,614	$0	$0	$91,614	$91,614	$91,614	$91,614
Post-retirement Health Care [9]	$0	$0	$0	$22,494	$0	$44,105	$0
Split-Dollar Policy [10]	$13,608	$0	$0	$13,608	$13,608	$26,651	$675,759
Executive AD&D Proceeds [11]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up [12]	$0	$0	$0	$0	$0	$1,564,756	$0
TOTAL	**$105,222**	**$0**	**$0**	**$1,458,266**	**$105,222**	**$6,309,979**	**$3,276,791**

[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 ($445,000) 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 (($445,000 + $245,000) 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 bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $445,000. 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, 2008, this is based on the full award. For 2008, Mr. Lyash's MICP award was $225,000.

[3] For the 2006 performance shares grant, the expected payout as of December 31, 2008 was 0%.

[4] 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, 2008, the performance factor is 100%. In the event of death or disability, the 2007 2-year transitional and 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 performance grant, a pro-rata payment would be made based upon time in the plan.

[5] 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, and would forfeit 4,790 restricted stock units granted on March 18, 2008.

[6] 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 7,300 restricted stock shares would vest immediately.

[7] 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, 2008, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[8] 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.

[9] 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 $1,249.64 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 $1,225.14 per month.

[10] The Executive Permanent Split-Dollar Life Insurance program involves sharing of insurance costs and benefits between the Company and the participant. The benefit sharing was scheduled to end at age 65. However, in 2008, the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. Mr. Lyash surrendered his policy for cash value. Surrender proceeds were issued in January 2009 equal to the greater of the 2008 projected cash surrender value per the original policy illustration or actual cash value at December 31, 2008, with a minimum of $5,000. At December 31, 2008, the program was still active and potential payments would have been due under the following events: Under voluntary termination, involuntary not for cause termination, and for cause termination, the policy would be split in proportion to cash value ownership. The amounts in these columns represent the 2008 projected cash surrender value per the original policy illustration. There is no provision for early retirement under the Split-Dollar program, and Mr. Lyash is not eligible for normal retirement. Under involuntary or good reason termination (CIC), this value represents premiums that would be paid by the Company for three years. In the event of death, proceeds of the Policy would be payable as of the last policy anniversary date.

[11] Mr. Lyash would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[12] 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 $2,885,621 of excess parachute payments above his base amount. Those excess parachute payments result in $577,124 of excise taxes, $965,267 of tax gross-ups, and $22,365 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—$440,000[1]	$0	$0	$0	$1,315,600	$0	$2,046,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$242,000	$210,000
Long-term Incentives							
Performance Shares (PSSP)							
~~2006 (performance period)[3]~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~
2007 2-yr Transitional Grant[4]	$0	$0	$0	$0	$0	$418,345	$418,345
2007 (performance period)[4]	$0	$0	$0	$0	$0	$418,345	$418,345
2008 (performance period)[4]	$0	$0	$0	$0	$0	$402,605	$109,801
Restricted Stock Units[5]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$62,804	$62,804
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$62,804	$62,804
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$62,764	$62,764
2007 Retention Grant (grant date vesting)	$0	$0	$0	$0	$0	$358,650	$358,650
2008 – 2009 (grant date vesting)	$0	$0	$0	$0	$0	$63,601	$0
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$63,640	$0
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$63,640	$0
Restricted Stock[6]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$338,725	$338,725
Benefits and Perquisites							
Incremental Nonqualified Pension[7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[8]	$427,147	$0	$0	$427,147	$427,147	$427,147	$427,147
Post-retirement Health Care[9]	$0	$0	$0	$22,936	$0	$44,972	$0
Split-Dollar Policy[10]	$25,165	$0	$0	$25,165	$25,165	$31,846	$855,170
Executive AD&D Proceeds[11]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[12]	$0	$0	$0	$0	$0	$1,563,461	$0
TOTAL	**$452,312**	**$0**	**$0**	**$1,790,848**	**$452,312**	**$6,671,349**	**$3,824,555**

[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's employment agreement requires a severance equal to 2.99 times his then current base salary ($440,000) 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 (($440,000 + $242,000) 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 bonus under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $440,000. 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, 2008, this is based on the full award. For 2008, Mr. Yates's MICP award was $210,000.

[3] For the 2006 performance shares grant, the expected payout as of December 31, 2008 was 0%.

[4] 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, 2008, the performance factor is 100%. In the event of death or disability, the 2007 2-year transitional and 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 performance grant, a pro-rata payment would be made based upon time in the plan.

[5] 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, and would forfeit 4,790 restricted stock units granted on March 18, 2008.

[6] 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's restricted stock grant dates are beyond the one-year threshold; therefore, all 8,500 restricted stock shares would vest immediately.

[7] 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, 2008, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[8] 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.

[9] 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 $1,274.20 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 $1,249.22 per month.

[10] The Executive Permanent Split-Dollar Life Insurance program involves sharing of insurance costs and benefits between the Company and the participant. The benefit sharing was scheduled to end at age 65. However, in 2008, the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. Mr. Yates surrendered his policy for cash value. Surrender proceeds were issued in January 2009 equal to the greater of the 2008 projected cash surrender value per the original policy illustration or actual cash value at December 31, 2008, with a minimum of $5,000. At December 31, 2008, the program was still active and potential payments would have been due under the following events: Under voluntary termination, involuntary not for cause termination, and for cause termination, the policy would be split in proportion to cash value ownership. The amounts in these columns represent the 2008 projected cash surrender value per the original policy illustration. There is no provision for early retirement under the Split-Dollar program, and Mr. Yates is not eligible for normal retirement. Under involuntary or good reason termination (CIC), this value represents premiums that would be paid by the Company for three years. In the event of death, proceeds of the Policy would be payable as of the last policy anniversary date.

[11] Mr. Yates would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[12] 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 $2,883,233 of excess parachute payments above his base amount. Those excess parachute payments result in $576,647 of excise taxes, $964,468 of tax gross-ups, and $22,346 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 2008.

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)
James E. Bostic, Jr.	$93,500	$22,877	—	—	—	$15,000	$131,377
David L. Burner	$118,500	$7,054	—	—	—	$15,819	$141,373
Richard L. Daugherty	$53,500	$177	—	—	—	$517,675[4]	$571,352
Harris E. DeLoach, Jr.	$103,500	$45,164	—	—	—	$15,000	$163,664
James B. Hyler, Jr.	$28,178	—	—	—	—	—	$28,178
Robert W. Jones	$93,500	$53,194	—	—	—	$9,677	$156,371
W. Steven Jones	$93,500	$36,684	—	—	—	$15,582	$145,766
E. Marie McKee	$107,000	$7,054	—	—	—	$16,038	$130,092
John H. Mullin, III	$108,500	$4,306	—	—	—	$15,000	$127,806
Charles W. Pryor, Jr.	$93,500	$53,194	—	—	—	$7,097	$153,791
Carlos A. Saladrigas	$93,500	$17,367	—	—	—	$15,000	$125,867
Theresa M. Stone	$102,030	$36,684	—	—	—	$15,000	$153,714
Alfred C. Tollison, Jr.	$101,500	$45,164	—	—	—	$16,841	$163,505

[1] Reflects the annual retainer plus any Board or Committee fees earned in 2008. Amounts may have been paid in cash or deferred into the Non-Employee Director Deferred Compensation Plan.

[2] Reflects the change in value in the Non-Employee Director Stock Unit Plan account for 2008. The value of account is tracked in phantom stock units and changes with the annual $60,000 grant, dividend reinvestment, unit appreciation/ depreciation and payments made upon termination of a director. 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 SFAS No. 123(R), the fair value of the Director Plan is re-measured at each financial statement date. The fair value of the Director Plan reflects the fair value of the Company's stock applied to the number of phantom stock units. The grant date fair value for each stock unit granted to each director on January 2, 2008 was $47.63. The numbers of stock units outstanding as of December 31, 2008, for each Director listed above are as follows: James E. Bostic Jr.—6,387; David L. Burner—9,024; Richard L. Daugherty—0; Harris E. DeLoach—2,673; James B. Hyler, Jr.—0; Robert W. Jones—1,335; W. Steven Jones—4,086; E. Marie McKee—9,024; John H. Mullin, III—9,482; Charles W. Pryor—1,335; Carlos A. Saladrigas—7,306; Theresa M. Stone—4,086; and Alfred C. Tollison, Jr.—2,673.

[3] Includes incentive matching contributions under the incentive compensation program, the value of perquisites such as tickets to sporting and cultural arts events, imputed income for personal or spousal travel, and the cash value of retirement and holiday gifts from the Company. For all directors who have been on our Board since January 1, 2007, the Company gave a $15,000 incentive match based on the Company's achievement of corporate incentive goals. The $15,000 incentive match was prorated for new directors based on the time they were elected to the Board.

[4] Includes a $500,000 contribution to colleges and universities of the director's choice pursuant to the Directors' Educational Contribution Plan. The Directors' Educational Contribution Plan is funded by policies of corporate-owned life insurance on the lives of pairs of Directors, with proceeds payable to us at the death of the second to die in each pair. All costs of the Directors' Education Contribution Plan are expected to be covered from the life insurance proceeds to be received by us. Mr. Richard L. Daugherty, who retired from the Board in 2008, was a participant in the Directors' Educational Contribution Plan. In 2008, we made a contribution of $500,000 on Mr. Daugherty's behalf to the Richard and Marlene Daugherty Centennial Campus Entrepreneurialism Endowment at North Carolina State University. In 2008, we paid insurance premiums totaling $392,075 in order to fund the Directors' Educational Contribution Plan. Only Directors who were Directors or retired Directors on or prior to September 16, 1998 can participate in the Directors' Educational Contribution Plan. Under these guidelines, none of the current Board members is eligible to participate, and the Directors' Educational Contribution Plan has been discontinued.

DISCUSSION OF DIRECTOR COMPENSATION TABLE

RETAINER AND MEETING FEES

During 2008, 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 non-chair 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 non-chair 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 Nuclear Project Oversight Committee was established on December 10, 2008. 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 non-customary 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.

DIRECTOR INCENTIVE COMPENSATION PLAN

In conjunction with the amendment of the Non-Employee Director Stock Unit Plan, the Board of Directors eliminated the Director Incentive Compensation Plan.

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.

PERQUISITES

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.

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.

All of the Directors who were Directors or retired Directors on or prior to September 16, 1998, participate in a Directors' Educational Contribution Plan. The Directors' Educational Contribution Plan is funded by policies of corporate-owned life insurance on the lives of pairs of Directors, with proceeds payable to us at the death of the second to die in each pair. All costs of the Directors' Educational Contribution Plan are expected to be covered from the life insurance proceeds to be received by us. Pursuant to the Director's Educational Contribution Plan, we will make a contribution in the name of each participating Director to an educational institution or approved educational foundation or fund in North Carolina or South Carolina selected by the participating Director and approved by the Executive Committee of the Board of Directors. The contribution will be made at the later of the retirement of the participating Director from the Board of Directors or 10 years from the date of adoption of the Directors' Educational Contribution Plan. If a participating Director has served as a Director for at least five but less than 10 years at the time the contribution is to be made, we will contribute $250,000 in the name of the Director. If the participating Director has served for 10 or more years, the amount of the contribution will be $500,000. Mr. Daugherty, who retired from the Board in 2008, was a participant in the Directors' Educational Contribution Plan. In 2008, we made a contribution of $500,000 on Mr. Daugherty's behalf to the Richard and Marlene Daugherty Centennial Campus Entrepreneurialism Endowment at North Carolina State University.

Only Directors who were Directors or retired Directors on or prior to September 16, 1998 can participate in the Directors' Educational Contribution Plan. Under these guidelines, none of the current Board members is eligible to participate, and the Directors' Educational Contribution Plan has been discontinued.

EQUITY COMPENSATION PLAN INFORMATION
as of December 31, 2008

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	4,901,385	$43.99	6,541,305
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4,901,385	$43.99	6,541,305

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, 2008, 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. 61, 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, 2008, for filing with the SEC.

Audit and Corporate Performance Committee

Theresa M. Stone, Chair
James E. Bostic, Jr.
James B. Hyler, Jr.
Charles W. Pryor, Jr.
Carlos A. Saladrigas
Alfred C. Tollison, Jr.

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 preapproving 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 preapproval policy, the Audit Committee specifically preapproved the use of Deloitte for audit, audit-related, tax and non-audit services.

The preapproval policy requires management to obtain specific preapproval 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 may include proposed services that provide significant economic or other benefits. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible 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 or a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and 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, 2008, and December 31, 2007.

	2008	2007
Audit fees	$3,673,000	$3,937,000
Audit-related fees	94,000	114,000
Tax fees	22,000	579,000
Total Fees	3,789,000	4,630,000

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) the audits of the financial statements of certain of our nonreporting subsidiaries in support of the audit of our financial statements; (v) accounting consultations arising as part of the audits; and (vi) 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 2008 and 2007 also include $1,264,000 and $1,263,000, 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) audits of the financial statements of certain of our nonreporting subsidiaries; (ii) special procedures and letter reports; (iii) benefit plan audits when fees are paid by us rather than directly by the plan; and (iv) 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 was approved 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, 2009, and has directed that management submit the selection of that independent registered public accounting firm for ratification by the shareholders at the 2009 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, 2009, 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—APPROVAL OF THE PROGRESS ENERGY, INC. 2009 EXECUTIVE INCENTIVE PLAN TO COMPLY WITH SECTION 162(m) OF THE INTERNAL REVENUE CODE

Background

The Board of Directors and Organization and Compensation Committee (the "Committee") have unanimously approved the adoption of the Progress Energy, Inc. 2009 Executive Incentive Plan (the "EIP") effective March 17, 2009, subject to shareholder approval of the EIP at the Annual Meeting of Shareholders as described in this proposal. Below is a description of the material terms of the EIP. The discussion is qualified in its entirety by reference to the EIP, a copy of which is attached to this Proxy Statement as Exhibit D. Shareholders should refer to the EIP for more complete and detailed information about the plan.

The EIP creates an annual cash incentive plan for the Company's named executive officers. Bonus awards under this program are payable in cash from a bonus pool based upon the operating earnings of the Company. In an attempt to preserve, to the extent practicable, the Company's ability to deduct compensation payable under the EIP to covered employees (generally, the named executive officers in the Proxy Statement), the Company is proposing that shareholders approve the material terms of the EIP.

Under Section 162(m) of the Internal Revenue Code of 1986, as amended ("Section 162(m) of the Code") and related regulations, compensation in excess of $1,000,000 paid in any one year to a public corporation's covered employees who are employed by the corporation at year-end will not be deductible for federal income tax purposes unless the compensation is considered "qualified performance-based compensation" under Section 162(m) of the Code (or another exemption is met). In order to qualify as performance-based compensation, among other requirements, Section 162(m) of the Code and related regulations require that shareholders approve the material terms of the performance goals under which compensation may be paid under a plan. The material terms subject to shareholder approval include: (i) the employees eligible to receive compensation; (ii) a description of the business criteria upon which the performance goal is based; and (iii) either the maximum dollar amount of compensation that may be paid to an employee during a specified period, or the formula used to calculate the amount of compensation to be paid, if the performance goal is met. These material terms are described below.

If the shareholders do not approve the material terms of the EIP, the Committee intends to revisit our cash incentive structure for our named executive officers for 2009, although it is anticipated that any such incentive program would continue to be performance-based and to emphasize at-risk compensation.

Purpose

The purpose of the EIP is to assist the Company in attracting, retaining, motivating and rewarding employees who occupy key positions and contribute to the growth and profitability of the Company through the award of cash incentives. The plan is also intended to enable the Committee to preserve the tax deductibility of incentive awards under Section 162(m) of the Code to the extent practicable.

Eligibility

Participants in the EIP are the principal executive officer and other executive officers of the Company as may be named by the Committee, subject to the provisions of Section 162(m) of the Code. Participants are selected on an annual or other periodic basis as determined by the Committee. At this time, approximately 5 employees (including the named executive officers) are eligible to participate in the EIP. Non-employee service providers and non-employee directors are not eligible to participate

Administration; Amendment and Termination

The EIP is administered by the Committee. The Committee may amend, suspend or terminate the EIP at any time, subject to: (i) shareholder approval of any amendments if required by applicable laws, rules or regulations; and (ii) participant consent if such action would materially adversely affect any award earned and payable under the plan at that time. The Committee also may adjust awards and performance objectives upon the occurrence of certain unusual or nonrecurring events or other similar circumstances, as described in the EIP. In addition, the Committee's authority to grant awards and authorize payments under the EIP does not restrict its authority to grant compensation to employees under another Company compensation plan or program.

Establishment of Incentive Pool; Award Limitations

For each performance period, an unfunded incentive pool will be established to measure Company performance and determine the amounts, if any, payable with respect to awards. The incentive pool for each performance period shall equal one percent (1%) of the Company's operating earnings (as defined in the EIP) for the performance period. Awards may be earned and paid under the EIP only if and to the extent the incentive pool is hypothetically funded as a result of Company operating earnings for the performance period.

For each performance period, the Committee will allocate a specified percentage or other amount of the incentive pool to each participant. The maximum amount payable for all awards during a performance period cannot exceed 100% of the incentive pool for that period. The maximum award payable to any one participant cannot exceed 40% of the incentive pool for that period. The Committee may decline to allocate any portion of the incentive pool.

Earning of Awards

The Committee will determine the amount of the incentive pool for a performance period and the amount of the incentive pool allocated to each participant for that performance period. The Committee may, in its discretion, decrease (but not increase) the individual award of a participant for the performance period based upon business criteria determined by the Committee and as typically executed through the Management Incentive Compensation Plan of Progress Energy, Inc. ("MICP"), the Company's principal cash incentive plan for executive officers, and such other factors as the Committee deems appropriate. As indicated above, the amount allocated to participants could be less than the incentive pool generated under this plan depending upon the Committee's judgment of Company performance, individual performance and contributions, and other factors the Committee deems relevant and prudent under the circumstances.

Effect of Termination of Employment

Except as otherwise provided in a separate contractual arrangement entered into between any participant and the Company or otherwise determined by the Committee in its sole discretion, a participant must be actively employed by the Company or an affiliate on the January 1 immediately following the year when an award is earned in order to be paid with respect to the award. No payment shall be made to or on behalf of a Participant who terminates employment prior to the end of a performance period for reasons other than the death or disability of the participant, or in the event of a Change in Control, if such payment would fail to qualify as "performance-based compensation" under Section 162(m) of the Code.

Certain Federal Income Tax Consequences

The following summary generally describes the principal U.S. federal (and not foreign, state or local) income tax consequences of awards granted under the EIP as of the date of this proxy statement. The summary is general in nature and is not intended to cover all tax consequences that may apply to a particular employee or to the Company. The provisions of Section 162(m) of the Code and related regulations concerning these matters are complicated and their impact in any one case may depend upon the particular circumstances.

In general, a participant in the EIP will be taxed at ordinary income rates on any cash bonus in the year received. Generally, the Company will receive a federal income tax deduction corresponding to the amount included in the participant's income (subject to compliance with the requirements of Section 162(m) of the Code described herein).

Performance-based Compensation — Section 162(m) Requirements. The EIP is structured to comply with the requirements imposed by Section 162(m) of the Code and related regulations in order to preserve, to the extent practicable, the Company's tax deduction for awards made under the EIP to covered employees. As described above, Section 162(m) of the Code generally denies an employer a deduction for compensation paid to covered employees of a publicly held corporation in excess of $1,000,000 unless the compensation is exempt from the $1,000,000 limitation because it is performance-based compensation.

New Plan Benefits

As noted above, awards made under the Plan are made at the Committee's discretion and are based on attainment of performance goals. Accordingly, it is not possible to determine at this time the amount of the awards that will be paid for the current fiscal year or the amount of future awards under the EIP. However, the cash bonuses that were paid to the named executive officers for fiscal year 2008 under the MICP are described above in the Summary Compensation Table under the heading "Non-Equity Incentive Plan Compensation" on page 40.

Approval of the proposal regarding the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code will require the affirmative vote of a majority of the votes cast 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 proposal regarding the Progress Energy, Inc. 2009 Executive Incentive Plan to comply with Section 162(m) of the Internal Revenue Code will not be included in determining the number of votes cast.

**YOUR BOARD OF DIRECTORS RECOMMENDS A VOTE <u>FOR</u>
THIS PROPOSAL**

FINANCIAL STATEMENTS

Our 2008 Annual Report, which includes financial statements as of December 31, 2008, and 2007, and for each of the three years in the period ended December 31, 2008, 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 6, 2009.

FUTURE SHAREHOLDER PROPOSALS

Shareholder proposals submitted for inclusion in the proxy statement for our 2010 Annual Meeting must be received no later than December 1, 2009, 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, NC 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 within the time limits described above. 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 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.

3. 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 material 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.

Exhibit B

Progress Energy, Inc. Corporate Governance Guidelines—Board Independence Section

B. Board Independence

In order for a director to be deemed "independent," the Board of Directors of the Company must affirmatively determine that the director has no material relationship with the Company, either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company. In making this determination, the Board of Directors shall apply the following standards:

1. A director who is, or has been within the last three years, an employee of the Company, or whose immediate family member is, or has been within the last three years, an executive officer, of the Company, is not independent. Employment as an interim Chairman or Chief Executive Officer will not disqualify a director from being considered independent following such employment.

2. A director who has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from the Company, other than director and committee fees and pensions or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service) is not independent. Compensation received by a director for former service as an interim Chairman or Chief Executive Officer will not be considered in determining independence under this standard. Compensation received by a director's immediate family member for service as an employee of the Company (other than as an executive officer) will not be considered in determining independence under this standard.

3. A director who is or has been within the last three years affiliated with or employed by (or whose immediate family member is or has been within the last three years affiliated with or employed by) a present or former internal or external auditor of the Company is not independent.

4. A director who is, or has been within the last three years, or whose immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the Company's present executives at the same time serve or served on that company's compensation committee is not independent.

5. A director who is an executive officer or an employee (or whose immediate family member is an executive officer) of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million or 2% of such other company's consolidated gross revenues is not independent.

6. A director who has or whose immediate family member has received any compensation from the Company directly or indirectly as an advisor or consultant is not independent until at least three years after he or she ceases to receive such compensation.

7. A director who is or whose immediate family member is an officer, director, or trustee of a foundation, university, or other tax-exempt organization that received from the Company, in any single year within the preceding three years, contributions in an amount which exceeded the greater of $1 million or 2% of such tax-exempt organization's consolidated gross revenues is not independent.

8. Neither a director nor his/her immediate family member shall receive any personal loans from the Company.

9. A director who had or whose immediate family member had, during the Company's last fiscal year, a relationship that must be disclosed under Item 404(a) of Regulation S-K is not independent.

10. Relationships not specifically mentioned above, or transactions that may have taken place prior to the adoption of these independence standards, may, in the Board's judgment, be deemed not to be material and the director will be deemed independent, if after taking into account all relevant facts and circumstances, the Board determines that the existence of such relationship or transaction would not impair the director's exercise of independent judgment.

11. Any transaction that Item 404(a) of Regulation S-K exempts from disclosure (or subjects to only limited disclosure) shall be deemed categorically immaterial for purposes of these Guidelines. These transactions include, but are not limited to, the following:

    - executive compensation arrangements otherwise reported under Item 402 of Reg. S-K (other than in the case of an immediate family member);
    - indebtedness incurred in connection with the purchase of goods and services on usual trade terms; ordinary business travel and expense payments; and other transactions in the ordinary course of business;
    - loans from banks, savings and loans and broker-dealers made in the ordinary course of business on prevailing market terms and not involving more than the normal risk of collectibility;
    - transactions in which the related person's interest arises solely because of his/her position as a director of and/or ownership of less than a 10% equity in another entity that is a party to the transaction;
    - transactions in which the related person's interest arises only from his/her position as a limited partner in a partnership in which the person and all other related persons have an interest of less than 10%;
    - transactions where the rates or charges involved are determined by competitive bids;
    - transactions that involve the rendering of services as a public utility at rates or charges fixed in conformity with law or a governmental authority; and
    - transactions in which the related person's interest arises solely from the ownership of a class of equity securities of the Company and all holders of such class of Company equity securities received the same benefit on a pro rata basis.

For purposes of these Guidelines, the following definitions shall apply:

a. "affiliate" means any subsidiary of the Company and any other Company or entity that controls, is controlled by or is under common control of the Company.

b. "immediate family" means a director's spouse, parents, stepparents, children, stepchildren, siblings, mothers-and fathers-in-law, sons-and daughters-in-law, brothers- and sisters-in-law and anyone (other than employees) who shares the director's home or who is financially dependent on the director.

The Board shall undertake an annual review of the independence of all non-employee Directors. In advance of the meeting at which this review occurs, each non-employee Director shall be asked to provide the Board with full information regarding the Director's business and other relationships with the Company and its affiliates and with senior management and their affiliates to enable the Board to evaluate the Director's independence.

Directors have an affirmative obligation to inform the Board of any material changes in their circumstances or relationships that may impact their designation by the Board as "independent" and to comply with the Company's Policy and Procedures with Respect to Related Person Transactions, which is attached hereto as Exhibit A. This obligation includes all business relationships between, on the one hand Directors or members of their immediate family, and, on the other hand, the Company and its affiliates or members of senior management and their affiliates, whether or not such business relationships are subject to the approval requirement set forth in the following provision.

The Board believes that having the Chief Executive Officer as a member of the Board is appropriate and can increase the Board's effectiveness and comprehension of the Company's business. Whether employees other than the Chief Executive Officer should serve on the Board is a matter determined based on the circumstances and what is deemed by the Board to be in the Company's best interest.

The identity of the independent directors will be disclosed in the Company's annual proxy statement.

Exhibit C

Progress Energy, Inc. Audit and Corporate Performance Committee Charter

PURPOSE AND COMPOSITION

The Audit and Corporate Performance Committee ("Committee") shall be a standing committee of the Board of Directors ("Board"). The Committee shall assist, advise, and report regularly to the Board in fulfilling its oversight responsibilities related to the integrity of the Company's financial statements, the Company's compliance with legal and regulatory requirements, the independent auditor's qualifications and independence, the performance of the Company's internal audit function and independent auditors, and the Corporate Ethics Program.

In meeting its responsibilities, the Committee is expected to provide an open channel of communication with management, internal audit, the external auditors, and the Board.

The Committee is composed of at least three members of the Board who are independent within the meaning of the Listing Standards of the New York Stock Exchange (NYSE). Committee members shall be appointed and/or removed by the Board. No member of the Committee shall be removed except by a majority vote of the independent directors then in office. Committee members shall be free from any relationships that would interfere with or give the appearance of interfering with the exercise of independent judgment as a Committee member. All members shall have a requisite working familiarity with basic finance and accounting practices in compliance with the Listing Standards of the NYSE. Furthermore, at least one member of the Committee shall have sufficient accounting or financial expertise and be designated as a "financial expert" in compliance with the Listing Standards of the NYSE. Committee members shall be appointed by the Board normally at the Annual Organizational Meeting of the Board.

Director's fees shall be the only compensation a Committee member may receive from the Company. The Board shall designate one Committee member as Chairman, who shall preside over the meetings of the Committee and report Committee actions to the Board.

DUTIES AND RESPONSIBILITIES

Duties and responsibilities of the Committee shall include, but are not limited to, the following:

1. Review with management and the external auditors the annual and quarterly financial results for the Company, including the disclosures under "Management's Discussion and Analysis of Financial Condition and Results of Operations." Discussions with management will also include earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies. The review should focus on appropriate disclosure of key events, risk assessment and management, and actual or contingent liabilities that could materially impact the Company's financial results or cause the reported information to be misleading. Review the annual report to shareholders, the annual/quarterly reports on Forms 10-K/10-Q filed with the Securities and Exchange Commission, and legal and regulatory matters having a material impact on the financial statements. The external auditors will have discussions with the Committee on the quality of the accounting policies and practices used by the Company, any alternative treatments of financial information, their ramifications and the external auditors' preferred treatments.

2. Oversee and monitor the work of the external auditors to ensure they are independent of management and their objectivity is not impaired, recognizing that the external auditors are accountable to the Board and the Committee. In determining the independence of the external

auditors, the Committee will annually obtain and review a formal report from the external auditors affirming their independence as prescribed by the NYSE. Review with the external auditors any audit problems or difficulties and management's response.

The Committee has sole authority to retain and terminate the Company's external auditors and will set clear hiring policies for employees or former employees of the independent auditors. Annually obtain and review a report from the external auditors describing the internal quality control process, including material issues raised by the most recent internal quality control review or by any inquiry or investigation by government, regulatory or professional authorities within the past five years.

Annually report to the Board the external audit firm(s) to be retained and preapprove all audit and non-audit services and fees as noted in the Committee's Preapproval Procedure. The Committee will review the scope of any non-audit services to be performed by the external auditors and determine its impact on the auditors' independence. Review the scope of the external audit plan and upon completion of the audit, review significant changes made in the scope of the audit plan. Meet with the external auditors privately, without management present, at each regular meeting.

3. Oversee and monitor the activities of the Audit Services Department to ensure the internal audit function maintains appropriate independence and objectivity in the fulfillment of its responsibilities. The Committee should review: the audit plan for the upcoming year; any planned significant outsourcing of internal audit work, and the results/changes made to the prior year's plan; significant audit findings and recommendations and management's action plans; the adequacy of the budget and staffing for the Department; and the appointment or dismissal and annual compensation of the Chief Audit Executive. Meet with the Chief Audit Executive privately, without management present, at each regular meeting.

4. Assess and monitor the overall control environment of the Company through discussions with management, the external auditors and the Chief Audit Executive. Assess the extent to which the audit plans of the external and internal auditors can be relied on to identify material internal control weaknesses or fraud.

5. Oversee and monitor the activities of the Corporate Ethics Program. As noted in the Committee's Complaint Procedure, the Committee will review and take appropriate action on any complaints received by the Company regarding questionable accounting, internal controls or auditing matters.

6. Review and discuss with management the Company's guidelines and policies governing risk assessment and risk management. Note: While the CEO and Senior Management have the responsibility to assess and manage the Company's exposure to risk and the Finance Committee is responsible for the oversight of the Risk Management Committee Policy and Guidelines, the Audit Committee must discuss in a general manner the guidelines and policies used to govern the process.

7. Request the external auditors, the internal auditors, or management to conduct special reviews or studies, as appropriate. Also, the Committee may obtain advice and assistance from outside legal, accounting or other advisors, at Company expense.

8. Provide a report in the proxy statement stating that the Committee has reviewed and discussed the financial statements with management and the auditors. In addition, this report will include a recommendation to the Board that the audited financial statements be included in the Company's annual report on Form 10-K.

9. Conduct an annual self-assessment of the effectiveness and performance of this Committee and review the adequacy of this Charter. This Charter and the Company's Code of Ethics will be published on the Company's website. In addition, the disclosure of this Charter will be stated annually in the proxy, which will contain a copy of the Charter in an appendix, as required.

MEETINGS

The Committee shall hold at least three regular meetings and four quarterly conference call meetings each year in order to accomplish the aforementioned duties and responsibilities. The Committee's Chairman may call additional meetings as needed, to review matters of interest to the Committee. The Committee may form subcommittees for any purpose that the Committee deems appropriate and may delegate to such subcommittees such power and authority as the Audit and Corporate Performance Committee deems appropriate. As deemed necessary by the Committee, meetings shall be attended by appropriate Company personnel.

Following each of its meetings, the Committee shall deliver a report on the meeting to the Board, including a description of all actions taken by the Committee at the meeting. The Committee shall keep written minutes of its meetings, which minutes shall be maintained with the books and records of the Company.

The President of the Service Company or his designee shall, at the request of the Chairman of the Committee, arrange meetings, prepare meeting agendas, and serve as Secretary to the Committee.

Exhibit D

PROGRESS ENERGY, INC.
2009 EXECUTIVE INCENTIVE PLAN
Effective March 17, 2009

1. Purpose. This Progress Energy, Inc. 2009 Executive Incentive Plan (the "Plan") is intended to assist Progress Energy, Inc. (the "Company"), and its Subsidiaries in attracting, retaining, motivating and rewarding employees who occupy key positions and contribute to the growth and profitability of the Company and its Subsidiaries through the award of certain incentives. The Plan also is intended to enable the Committee to preserve, to the extent practicable, the tax deductibility of incentive awards under Section 162(m) of the Code.

2. Definitions. For purposes of the Plan, the following terms are defined as set forth below, in addition to the terms defined in Section 1 and elsewhere in the Plan:

"Beneficiary" means the legal representatives of the Participant's estate entitled by will or the laws of descent and distribution to receive the benefits under a Participant's EIP Award upon a Participant's death, provided that, if and to the extent authorized by the Committee, a Participant may be permitted to designate a Beneficiary, in which case the "Beneficiary" instead will be the person, persons, trust or trusts (if any are then surviving) which have been designated by a Participant in his or her most recent written beneficiary designation filed with the Committee to receive the benefits specified under the Participant's Individual Award upon such Participant's death.

"Board" means the Company's Board of Directors.

"Change in Control" and related terms shall have the same meanings as defined in the MICP, unless otherwise defined in a separate contractual arrangement entered into between any Participant and the Company.

"Code" means the Internal Revenue Code of 1986, as amended from time to time, including regulations thereunder and successor provisions and regulations thereto.

"Committee" means the Organization and Compensation Committee of the Board or such other committee of the Board that is appointed by the Board. It is intended that each member of the Committee shall satisfy the requirements to be an "outside director," as defined in Section 162(m) of the Code; provided, however, that no action of the Committee shall be void or deemed beyond the authority of the Committee solely because one or more members fail to so qualify at any time.

"Covered Employee" means an employee of the Company or a Subsidiary if, as of the close of the fiscal year of the Company, the employee is the principal executive officer of the Company, or one of the other named executive officers in the annual proxy statement of the Company, subject to the provisions of Section 162(m) of the Code.

"Earnings" means the operating income of the Company for the Performance Period as determined from time to time by the Committee.

"Eligible Employee" means an employee of the Company or any Subsidiary who is a Covered Employee, or any other executive of the Company as determined by the Committee

"EIP Award" means Individual Awards that may be potentially payable pursuant to this Plan.

"Incentive Pool" means the pool of hypothetical funds specified under Section 4(a) for any given Performance Period out of which Individual Awards may be paid.

"Individual Award" means the percentage or other amount of the Incentive Pool allocated and potentially payable to a Participant, as provided in Section 4(d).

"MICP" means the Management Incentive Compensation Plan of Progress Energy, Inc., as amended or restated from time to time.

"Participant" means an Eligible Employee who has been selected by the Committee to participate in the Plan for a designated Performance Period pursuant to Section 4(c) of the Plan.

"Performance Measure" means the Earnings of the Company for the Performance Period.

"Performance Period" means the fiscal year of the Company, or such shorter or longer period as determined by the Committee in its discretion.

"Subsidiary" means, other than the Company, (i) any corporation in an unbroken chain of corporations beginning with the Company which owns stock possessing fifty percent (50%) or more of the total combined voting power of all classes of stock in one of the other corporations in such chain; (ii) any corporation or trade or business (including, without limitation, a partnership or limited liability company) which is controlled fifty percent (50%) or more (whether by ownership of stock, assets or an equivalent ownership interest or voting interest) by the Company or one of its Subsidiaries; or (iii) any other entity in which the Company or any of its Subsidiaries has a material equity interest and which is designated as a "Subsidiary" by resolution of the Committee.

3. Administration.

The Plan shall be administered by the Committee. The Committee shall have the exclusive authority and responsibility to: (i) interpret the Plan; (ii) subject to Sections 4(c) and 5 hereof, select Eligible Employees to become Participants and remove such Participants from participation in the Plan; (iii) allocate the Incentive Pool as Individual Awards; (iv) certify attainment of the Performance Measure and other material terms; (v) reduce Individual Awards as provided herein; (vi) authorize the payment of all benefits and expenses of the Plan as they become payable under the Plan; (vii) adopt, amend and rescind rules and regulations relating to the Plan; and (viii) make all other determinations and take all other actions necessary or desirable for the Plan's administration including, without limitation, correcting any defect, supplying any omission or reconciling any inconsistency in this Plan in the manner and to the extent it shall deem necessary to carry this Plan into effect, but only to the extent any such action would be permitted under Section 162(m) of the Code.

Decisions of the Committee shall be made by a majority of its members. All decisions of the Committee on any question concerning the selection of Participants and the interpretation and administration of the Plan shall be final, conclusive and binding upon all parties. The Committee may rely on information, and consider recommendations, provided by the Board or the executive officers of the Company. The Plan is intended to comply with Section 162(m) of the Code, to the extent practicable, and all provisions contained herein shall be limited, construed and interpreted in a manner to so comply.

4. The Incentive Pool.

(a) *Creation of Incentive Pool.* The Incentive Pool for each Performance Period of the Company shall equal one percent (1%) of the Earnings of the Company for such Performance Period. The Incentive Pool shall be an unfunded pool established for the purpose of measuring performance of the Company to determine potential compensation in connection with Individual Awards.

(b) *Individual Awards Payable Only Out of Incentive Pool.* Individual Awards may be earned and become payable under the Plan only if and to the extent the Incentive Pool, specified in Section 4(a), has become hypothetically funded.

(c) *Eligibility and Participation.* Not later than the time at which 25% of the applicable Performance Period has elapsed, but in no event later than 90 days after the Performance Period commenced, the Committee shall designate the Eligible Employees whom it has determined shall be Participants for that Performance Period.

(d) *Allocation of Individual Awards Payable Out of Incentive Pool.* Not later than the time at which 25% of the applicable Performance Period has elapsed, but in no event later than 90 days after the Performance Period commenced, the Committee shall allocate a specified percentage or other amount of the Incentive Pool to each such Participant, subject to Section 4(f). The allocation of the Incentive Pool need not be strictly a fixed percentage (thus, for example, it may be a percentage of the Incentive Pool above a defined threshold, a fixed dollar amount at a specified level of hypothetical funding, or varying percentages of the Incentive Pool depending on the level of the hypothetical funding), so long as no amount may be payable to the Participant except as allocated from the Incentive Pool by the Committee and no hypothetical funding level or other circumstance possibly can arise in which the amount payable (including amounts previously paid) in accordance with all Individual Award allocations for a given Performance Period will exceed 100% of the Incentive Pool for the applicable Performance Period. In all cases, the maximum Individual Award payable to any Participant shall be subject to the limitation set forth in Section 4(f). The Committee also is authorized to decline to allocate or designate for allocation all or a portion of the Incentive Pool.

(e) *Other Terms of Awards Established by the Committee.* The Committee may in its discretion specify other terms and conditions of the Individual Award. Except as otherwise provided in a separate contractual arrangement entered into between any Participant and the Company or otherwise determined by the Committee in its sole discretion, upon termination of a Participant's employment prior to the end of a Performance Period for any reason or no reason, the Participant shall not be entitled to any payments pursuant to this Plan with respect to such Performance Period; provided, however, that such termination shall not affect the allocation or amount of the payout to another Participant. Except in the case of the death or disability of the Participant, or in the event of a Change in Control, no payment shall be made to or on behalf of a Participant who terminates employment prior to the end of a Performance Period if such payment would fail to qualify as "performance-based compensation" under Section 162(m) of the Code.

(f) *Maximum Award Payable to Any One Participant.* Other provisions of the Plan notwithstanding, no Participant may be paid, in connection with Individual Awards under the Plan for any one Performance Period, an amount that exceeds 40% of the Incentive Pool generated for that Performance Period.

(g) *Payout of Individual Awards.* As soon as administratively feasible after the end of each Performance Period, the Committee shall determine the amount, if any, of the Incentive Pool for that Performance Period, and the amount resulting from each Participant's Individual Award based on the Participant's allocation of the Incentive Pool for that Performance Period and the terms and conditions of the Individual Award. Thereupon (but subject to Section 4(h)), the Committee shall pay out and settle the Individual Award, subject to the following:

(i) Unless a Participant elects to defer payment of an Individual Award as provided in subparagraph (iii) below, the Committee shall pay out and settle the Individual Award in cash no later than March 15 following the end of the Performance Period;

(ii) If a Participant dies after the end of a Performance Period but prior to payout (or settlement of any deferral) of an Individual Award for that Performance Period, any payments due to such Participant shall be paid to the Participant's Beneficiary;

(iii) Each Participant shall have the right to defer, in accordance with the terms and conditions of the MICP, receipt of part of all of any payment due with respect to such Individual Award; provided, however, that the terms of such deferral shall comply with the requirements of Section 409A of the Code and shall not cause any EIP Award under this Plan to fail to qualify as "performance-based compensation" under Section 162(m) of the Code; and

(iv) In connection with any payout in settlement of an Individual Award, the Committee shall post a corresponding debit to the Incentive Pool for the relevant Performance Period.

Notwithstanding anything in this Plan to the contrary, the Committee may, in its discretion, decrease the amount of the Individual Award payable with respect to the applicable Performance Period based on such factors as it deems appropriate (including, but not limited to, corporate, business unit/division or individual performance factors applicable under the MICP); provided, however, that the exercise of such discretion in respect of one Participant shall not affect the allocation or amount of the payout to another Participant.

(h) *Written Certifications.* Determinations by the Committee as to the level of the Performance Measure actually achieved and the resulting hypothetical funding of the Incentive Pool, the amount potentially payable in respect of each Individual Award, the final amount, if any, payable in settlement of each Individual Award, the satisfaction of other material terms of the Individual Award, and other matters relating to Individual Awards shall be certified in writing prior to the payout and settlement of the Individual Award.

5. Adjustments.

The Committee is authorized at any time during or after a Performance Period to adjust or modify the terms of the EIP Awards or the calculation of the Performance Measure or specify new Individual Awards, (i) in the event of any large, special and non-recurring dividend or other distribution, recapitalization, reorganization, merger, consolidation, spin-off, combination, repurchase, share exchange, liquidation, dissolution or other similar corporate transaction, (ii) in recognition of any other unusual or nonrecurring event affecting the Company or the financial statements of the Company (including events described in (i) above as well as acquisitions and dispositions of businesses and assets and extraordinary items determined under generally accepted accounting principles), or (iii) in response to changes in applicable laws and regulations, accounting principles, and tax rates (and interpretations thereof) or changes in business conditions or the Committee's assessment of the business strategy of the Company. No such adjustment shall be authorized or made if and to the extent that the existence of such authority would cause EIP Awards granted under the Plan to Participants intended to qualify as "performance-based compensation" under Section 162(m) of the Code to otherwise fail to qualify as "performance-based compensation."

6. Change in Control.

(a) *Payments Relating to Prior Performance Period Individual Awards.* Any provision of the Plan to the contrary notwithstanding, in the event of a Change in Control, the Committee may not exercise any discretion conferred under Section 5 to reduce the amount payable in respect of any Individual Award relating to a Performance Period which ended prior to the date of such Change in Control but which Individual Award had not been paid out at the time of the Change in Control, and all such Individual Awards shall be paid out entirely in cash as promptly as practicable following the Change in Control, unless this right has been waived by the Participant.

(b) *Payments Relating to Current Performance Period's Individual Awards.* A Participant's rights with respect to any EIP Award relating to the Performance Period in which the Change in Control occurs shall be governed by the terms of the Individual Award, rules and regulations under the Plan, and any previously executed agreement between the Participant and the Company or a Subsidiary then in effect.

7. General Provisions.

(a) *Nontransferability.* No EIP Award payable under, or right or interest in, the Plan shall be transferable by a Participant except upon a Participant's death by will or the laws of descent and distribution or to a Beneficiary, or otherwise shall be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, or charge, and any such attempted action shall be void.

(b) *Tax Withholding.* The Company and any Subsidiary is authorized to withhold from any payout of an EIP Award granted, or any payroll or other payment to a Participant, amounts of withholding and other taxes due or potentially payable in connection with any transaction involving an EIP Award, and to take such other action as the Committee may deem advisable to enable the Company and Participants to satisfy obligations for the payment of withholding taxes and other tax obligations relating to any EIP Award.

(c) *Changes to the Plan.* The Committee may amend, suspend, or terminate the Plan without the consent of shareholders or Participants; provided, however, that any amendment to the Plan shall be submitted to the Company's shareholders for approval if such shareholder approval is required by any federal or state law or regulation or the rules of any stock exchange or automated quotation system on which the common stock of the Company may then be listed or quoted, and the Committee may otherwise, in its discretion, determine to submit other amendments to the Plan to shareholders for approval; and further provided that no amendment, suspension or termination shall, without the consent of the Participant, materially alter or impair a Participant's right to receive payment of an EIP Award otherwise payable hereunder.

(d) *Limitation on Rights Conferred under Plan.* Neither the Plan nor any action taken hereunder shall be construed as (i) giving any Participant the right to continue as a Participant or in the employ or service of the Company or a Subsidiary, (ii) interfering in any way with the right of the Company or a Subsidiary to terminate any Participant's employment or service at any time, or (iii) giving a Participant any claim to any grant under the Plan or to be treated uniformly with other Participants and employees. In addition, until the Committee has determined to make a final Individual Award under Sections 4 or 5, respectively, a Participant's selection to participate, the initial determination of an EIP Award, and other actions taken with respect to the Plan shall not be construed as a commitment that any EIP Award shall become a final EIP Award or that any payment will be made with respect to an EIP Award under the Plan.

(e) *Unfunded Status of Awards; Creation of Trusts.* The Plan is intended to constitute an "unfunded" plan for incentive compensation. With respect to any payments not yet made to a Participant, nothing contained in the Plan or any Individual Award shall give any such Participant any rights that are greater than those of a general creditor of the Company; provided that the Committee may authorize the creation of trusts and deposit therein cash or other property, or make other arrangements to meet the Company's obligations under the Plan. Such trusts or other arrangements shall be consistent with the "unfunded" status of the Plan unless the Committee otherwise determines with the consent of each affected Participant.

(f) *Nonexclusivity of the Plan.* Neither the adoption of the Plan by the Board nor its submission of any terms of the Plan to the shareholders of the Company for approval shall be construed as creating any limitations on the power of the Board or a committee thereof to adopt such other incentive arrangements, apart from the Plan, as it may deem desirable, including incentive arrangements and awards which do not qualify under Section 162(m) of the Code, and such other arrangements may be either applicable generally or only in specific cases.

(g) *Compliance with Section 162(m) of the Code.* It is the intent of the Company that compensation under the Plan to Participants shall constitute qualified "performance-based compensation" within the meaning of Section 162(m) of the Code, unless otherwise determined by the Committee. Accordingly, the terms of Sections 4 and 5 and other provisions of the Plan, including the definitions and other terms used therein, shall be interpreted in a manner consistent with Section 162(m) of the Code. If any provision of the Plan or any document relating to an EIP Award that is designated as intended to comply with Section 162(m) of the Code does not comply or is inconsistent with the requirements of Section 162(m) of the Code, such provision shall be construed or deemed amended to the extent necessary to conform to such requirements, and no provision shall be deemed to confer upon the Committee or any other person discretion to increase the amount of compensation otherwise payable in connection with any such EIP Award upon attainment of the applicable performance objectives.

(h) *Severability; Entire Agreement.* If any of the provisions of this Plan or any EIP Award document is finally held to be invalid, illegal or unenforceable (whether in whole or in part), such provision shall be deemed modified to the extent, but only to the extent, of such invalidity, illegality or unenforceability, and the remaining provisions shall not be affected thereby; provided, that, if any of such provisions is finally held to be invalid, illegal, or unenforceable because it exceeds the maximum scope determined to be acceptable to permit such provision to be enforceable, such provision shall be deemed to be modified to the minimum extent necessary to modify such scope in order to make such provision enforceable hereunder. The Plan and any EIP Award documents contain the entire agreement of the parties with respect to the subject matter thereof and, unless specified otherwise, supersede all prior agreements, promises, covenants, arrangements, communications, representations and warranties between them, whether written or oral with respect to the subject matter thereof.

(i) *Governing Law.* The validity, construction and effect of the Plan, and any rules and regulations under the Plan, shall be determined in accordance with the laws of the State of North Carolina applicable to contracts made and to be performed in the State of North Carolina to the extent not preempted by federal law.

(j) *Plan Effective Date and Termination.* The Plan shall become effective as of the date of its adoption by the Board, subject to shareholder approval, and shall continue in effect until terminated by the Board pursuant to Section 7(c).

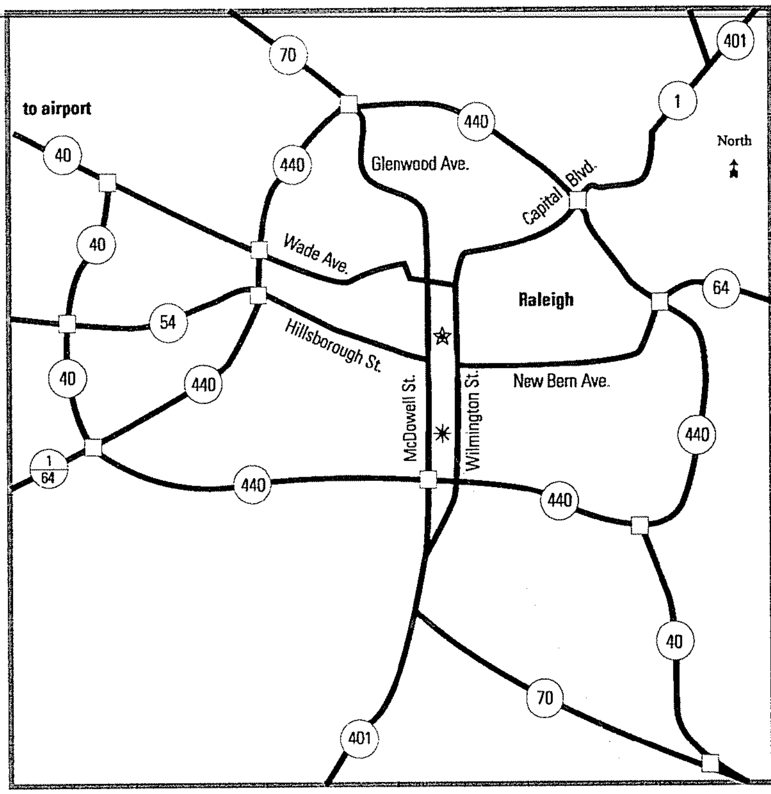
IN WITNESS WHEREOF, this instrument has been executed this _____ day of __________, 2009.

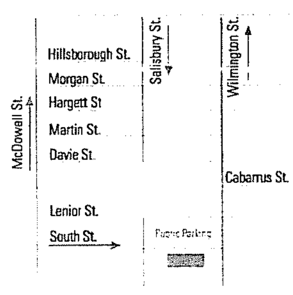
PROGRESS ENERGY, INC.

By: ____________________________
William D. Johnson
Chief Executive Officer

Directions to Progress Energy's 2009 Annual Shareholders' Meeting

Progress Energy Center for the Performing Arts
2 E. South Street, Raleigh, North Carolina





Progress Energy Center for the Performing Arts

002CS-61034

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.

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.

David L. Burner

Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services). Darby, Mont.

Elected to the board in 1999 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

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; Audit and Corporate Performance.

Robert W. Jones

Senior Advisor, Morgan Stanley (global provider of financial services to companies, governments and investors). Bedford, N.Y.

Elected to the board in 2007 and sits on the following committees. Finance; Organization and Compensation.

W. Steven Jones

Dean (Emeritus) and Professor of Strategy of 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. Nuclear Project Oversight; Operations and Nuclear Oversight; Organization and Compensation.

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 value-added 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 mid-sized companies). 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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