Duke Energy. Carolinas

Duke Energy Carolinas, LLC

Direct Testimony
North Carolina Utilities Commission
Docket No. E-7, Sub 909

June 2009

Volume 1 of 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	B. KEITH TRENT
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is B. Keith Trent, and my business address is 526 South Church Street, Charlotte, North Carolina. I am Group Executive and Chief Strategy, Policy and Regulatory Officer of Duke Energy Corporation ("Duke Energy"), the parent of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"). I am an officer of Duke Energy Carolinas.

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL AND PROFESSIONAL AFFILIATIONS.

A. I received a Bachelor's of Science Degree in Electrical Engineering, with honors, from Southern Methodist University and a Juris Doctor Degree, with high honors, from the University of Texas College of Law. I also completed the Harvard Business School Advanced Management Program. I am licensed to practice law in North Carolina and Texas, as well as numerous federal district courts and the United States Supreme Court. I am a member of the board of directors of Bright Automotive, Inc., and I am co-chair of The Keystone Energy Board. I serve on the board of visitors of the Wake Forest University Babcock Graduate School of Management and Charlotte Country Day School. I am also a member of various bar associations.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy in May 2002 as General Counsel, Litigation. I was responsible for managing all major litigation and government investigations for the company. The labor and employment and environmental, health and safety legal teams also reported to me. I was named group vice president, general counsel and secretary in June 2005 and group executive and chief development officer in April 2006. In that role, I led corporate development, including corporate strategy, and mergers and acquisitions. I was named group executive and chief strategy and policy officer in September 2006. I was named to my current position in April 2007. Before coming to Duke Energy in 2002, I served as a partner in the law firm Snell, Brannian and Trent. Prior to that I was an attorney at Jackson Walker in Dallas, Texas. I began my career as a reservoir/production engineer with ARCO Oil & Gas in Houston in 1982.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for Duke Energy's strategy, state and federal policy and government affairs, technology initiatives, corporate communications, community affairs, information technology, and environment, health and safety policy. In connection with my position, each of the presidents of Duke Energy's utility operating companies reports to me, and thus I am responsible for regulatory strategy and policy for Duke Energy Carolinas.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to discuss, at a high level, the reasons for our request for a $496 million (12.6%) rate increase. As a part of this discussion I will highlight the challenges our industry is facing – challenges that will continue for the foreseeable future. In addition, I will discuss actions we are taking to prepare for these challenges. I also discuss ways that the Company is mitigating the impact of this increase upon our customers, including specifically the fact that although we are requesting that the Commission approve a 12.3% return on equity (Duke Energy Carolinas' cost of equity capital, as supported by our expert ROE witness, Dr. James Vander Weide), we are proposing that actual rates be set using a lower, 11.5% return on equity figure. Finally, my testimony also provides an overview of the testimony of other witnesses submitting testimony on behalf of the Company in this proceeding.

II. REASONS FOR THE REQUESTED RATE INCREASE

Q. WHY IS DUKE ENERGY CAROLINAS REQUESTING A RETAIL ELECTRIC RATE INCREASE?

A. The primary reason is that our capital investments in production, transmission and distribution assets used to provide service to our Carolinas customers – our "rate base" – has increased significantly since our rates were last adjusted, to the point that current rates are not producing sufficient revenues to allow the Company to meet its day to day expenses and also provide a reasonable return for our investors. Maintaining financial strength and credit quality is always important for capital-intensive businesses such as electric utilities, but is critically important today given our increasing capital needs and the tightened credit markets.

For example, Duke Energy Carolinas (total company, both North Carolina and South Carolina) has experienced the following increases since the 2006 test period (the test period which was used in the last general rate case):

- An increase of approximately $2.8 billion in gross electric plant in service through the end of 2008, including: the purchase of an additional ownership interest in the Catawba Nuclear Station from Saluda River Cooperative, Inc. (approximately $150 million) and the addition of selective catalytic reduction ("SCR") equipment at the Marshall Steam

Station (approximately $100 million); as well as transmission and distribution investments totaling approximately $1 billion; and over $700 million in investments in our existing generation fleet related to significant upgrades, refurbishment, reliability, environmental and other regulatory compliance, and relicensing; and $1 billion associated with North Carolina Clean Smokestacks costs that have been recovered through amortization.

- Additional near-term expected rate base additions of approximately $1.0 billion including $500 million relating to the Allen Station flue gas desulfurization equipment or "scrubbers"; and

- Construction-work-in-progress investments at Cliffside Unit 6 of approximately $700 million as of year-end 2008 which is expected to grow to approximately $1 billion by the end of September 2009.

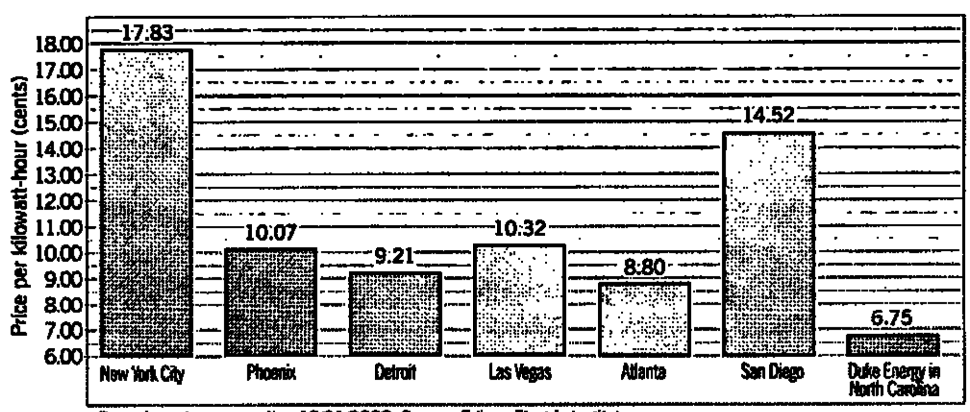
With these investments and our on-going operating expenses, our current rates (as adjusted by our proposed pro forma adjustments) are producing an overall rate of return of 5.88%, and a 5.92% return on equity invested in our Company – well below the returns authorized by the Commission in our most recent rate case. These returns are significantly below our cost of capital and what is necessary to continue to attract needed capital for our business, particularly in these tight credit markets.

Notably, without the rate decrease agreed to and approved in 2007, which resulted in a 7.5% and $287 million annual decrease in rates, the rate increase we would be proposing today would be less than 6% and approximately $200 million.

Also notably, this will be Duke Energy Carolinas' first general rate increase since 1991. Although our Company and other southeastern electric utilities were able to operate for many of years without general rate increases, the current environment of increasing capital expenditure requirements, increasing O&M costs over time, and lower load growth has brought that era of no general rate increases to an end. This is illustrated not only by the instant rate filing, but also by recent general rate increases requested by other utilities.[1] Finally, even with our requested rate increase, on an inflation-adjusted basis our all-in average North Carolina retail electric rates will be lower than our rates were in 1991.

Currently, our average North Carolina retail electric rate is approximately 31% below the current national average retail electric rate, and approximately 24% below the current South Atlantic regional average retail electric rate. Even with our requested 12.6% rate increase, our rates will remain highly competitive, both nationally and regionally. The following chart, which compares Duke Energy Carolinas' total average electric rates to those in various cities across the United States, graphically illustrates our rate competitiveness.

Total Retail Average Electric Rates*



*Rates from the year ending 12/31/2008. Source: Edison Electric Institute

III. CHALLENGES FACING THE ELECTRIC UTILITY INDUSTRY AND DUKE ENERGY CAROLINAS

Q. HOW WOULD YOU DESCRIBE THE CURRENT CHALLENGES

[1] For example, Florida Power & Light Co. and Florida Power Corp. both filed for rate increases with the Florida Public Service Commission in March of this year, and Virginia Electric Power Co. filed for a rate increase from the Virginia Commission, also in March of this year.

FACING THE ELECTRIC UTILITY INDUSTRY TODAY?

A. The challenges facing our industry today are great – perhaps the greatest ever. Our Company, along with many others, is facing the need to upgrade and modernize significant portions of our generation, transmission and distribution systems, as well as incorporate new technology into our power systems, and of course, continue to reliably meet our customers' demand for electricity. In addition to the significant costs associated with complying with existing state and federal environmental and other regulatory requirements (*e.g.*, environmental requirements, NRC requirements, NERC requirements, *etc.*), we are facing expected greenhouse gas reduction requirements in the near future.

A recent Brattle Group report[2] summarizes the challenges facing our industry as follows:

- By 2030, the electric utility industry will need to make a total infrastructure investment of $1.5 trillion to $2.0 trillion.

- As much as 214 gigawatts (GWs) of new generation capacity may be required by 2030, at an investment cost of $697 billion.

- Energy efficiency ("EE") and demand response ("DR") programs could reduce, but will not eliminate, the need for new generation capacity.

- Reductions in generation capacity requirements, though, do not mean an equal reduction in total investment, due in part to offsetting the cost of utility EE/DR programs.

- All types of generation capacity are needed. For the country as a whole, every type of power plant, including those fueled by natural gas, coal, nuclear, and renewable sources will play a significant role in the projected expansion plan.

- Implementation of a new federal carbon policy will significantly increase the cost and change the mix of new generation capacity. Under this scenario, Brattle anticipates that some fossil-based plants would be retired sooner than

[2] "Transforming America's Power Industry: The Investment Challenge 2010 to 2030," prepared for the Edison Foundation by the Brattle Group, November 2008.

they otherwise would have been; and the electric industry would increase investments in renewable energy and nuclear plants.

- Required transmission and distribution ("T&D") investment could be as large as, or larger than, generation investment. The combined investment in new T&D during this period will total about $880 billion, including $298 billion for transmission and $582 billion for distribution. These investments will enable the industry to integrate the approximately 39 GWs of renewable energy already mandated under state renewable portfolio standards ("RPS").

Q. DO YOU GENERALLY AGREE WITH THE BRATTLE GROUP'S SUMMARY OF THE CHALLENGES FACING THE ELECTRIC UTILITY INDUSTRY?

A. Yes, I do generally agree with the Brattle Group's summary of the challenges facing our industry. I also agree with the Brattle Group's ultimate conclusion, which is that clean, affordable, reliable electricity is essential to the global economy of the 21st century, just as it was to the American economy of the 20th century. The United States electric utility industry is capable of rising to these enormous challenges, but appropriate legislative and regulatory policies will be essential if we are to succeed.

Q. FOCUSING JUST ON GREENHOUSE GAS REDUCTION REQUIREMENTS RIGHT NOW, WHAT IN YOUR VIEW WILL BE THE IMPACT OF THIS ISSUE ON THE ELECTRIC UTILITY SECTOR?

A. The electric utility sector will play a large role in greenhouse gas emissions reductions under a federal cap-and-trade regime. Our sector accounts for 39% of CO2 and 33% of greenhouse gases produced in the United States – more than any other emitting sector in the country. The reduction targets will almost certainly require a transformational change in how power is generated, delivered, and consumed, and that transformation will be costly. Older coal-fired generating units will be retired, and will need to be replaced with new infrastructure investments involving a combination of gas-fired generation, nuclear generation, renewable generation, smart grids, and energy efficiency. At the same time, we must recognize that coal is an important resource and will play a role in the future. This is why we proposed the Cliffside Modernization Project as part of a bridge to a low carbon future. Cliffside Unit 6 is more carbon-efficient than existing coal units and enables the retirement of 1,000 MWs of older, less efficient coal-based resources between 2012 and 2018. Although we do not yet know precisely what form greenhouse gas regulation will take, the impact on our industry, our Company, and our customers is expected to be substantial – particularly if utilities are required to obtain all or a substantial portion of their needed CO2 allowances in an auction.

Q. HOW WILL THESE CHALLENGES FACING THE INDUSTRY AS A WHOLE IMPACT DUKE ENERGY CAROLINAS IN PARTICULAR?

A. Duke Energy Carolinas is impacted by these challenges in significant ways. For example:

- Our coal fleet is on average 53 years old, and our nuclear generation system is on average almost 29 years old.
- Our hydroelectric fleet is on average approximately 80 years old.
- Our transmission and distribution system is aging as well – on average, most of the system is over 20 years old, and the transmission system itself is almost 35 years old on average.
- We will need to make substantial capital investments required going forward, to replace aging and retired infrastructure, and to invest in new, more efficient technologies (for example, smart grid systems).

- We continue to make significant investments such as the Allen scrubbers and the Marshall SCR to meet environmental requirements, such as the Clean Smokestacks Act and Phase 1 of the Federal Clean Air Interstate Rule ("CAIR"), which begins in 2009 for NOx and in 2010 for SO_2 unless and until the Environmental Protection Agency ("EPA") promulgates a new rule.[3]

- Greenhouse gas regulation will require even more substantial investments, as older fossil-fuel generating units are retired, new generation sources are constructed, and new energy efficiency and demand response programs are put in place.

- Even in a recession, peak demand for electricity continues to grow (though at a slower rate), and energy use is remaining fairly constant in the Carolinas, with growth expected to accelerate when the economy rebounds. National historical data shows that after a recession, electricity demand grows quickly and dramatically as the recovery gains momentum. Duke Energy Carolinas must continue to make the investments necessary to stand ready to power the economic recovery.

All told, our current three year (2009-2011) capital budget for Duke Energy Carolinas is approximately $8 billion, which as Company Witness De May discusses, exceeds by approximately $2.0 billion the level spent by the Company between 2006-2008, and includes significant capital expenditures for the Cliffside Unit 6 project and in new gas-fired generation units, in addition to on-going environmental and NRC compliance costs. It is therefore imperative that Duke Energy Carolinas continue to maintain its strong credit rating, so as to continue to be able to maintain access to the capital markets on reasonable terms in order to finance its future capital needs.

Q. HOW WOULD YOU CHARACTERIZE THE CURRENT ECONOMIC ENVIRONMENT IN WHICH DUKE CAROLINAS OPERATES?

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[3] The EPA finalized its CAIR rule in May 2005. On July 11, 2008, however, the D.C. Circuit issued a decision in a challenge to the legality of the rule, in *North Carolina v. EPA* No. 05-1244, vacating the CAIR rule. The EPA filed a petition for rehearing on September 24, 2008 with the D.C. Circuit asking the court to reconsider various parts of its ruling vacating CAIR. In December of 2008, the D.C. Circuit issued a decision remanding the CAIR to EPA without vacatur. EPA must now conduct a new rulemaking to modify the CAIR in accordance with the court's July 11, 2008 opinion. This decision means that the CAIR as initially finalized in 2005 remains in effect until the new EPA rule takes effect.

A. As everyone is aware, we are currently in the midst of a significant global recession, stemming from the combination of subprime mortgages and risky derivative mortgage-backed securities, and resulting in a severe worldwide credit crisis that continues today.

As one of the most capital intensive segments of the economy, the electric utility industry is greatly affected by this financial and credit crisis. In his testimony, Dr. Vander Weide discusses in detail the macroeconomic risks associated with the state of the United States economy as well as the effect of that risk upon investing in electric utility companies. The bottom line is that capital (both debt and equity) is scarce and more expensive, and maintaining credit quality is of critical importance. The testimony presented by Witnesses Fetter and De May highlights the fact that the Company must maintain its credit ratings in order to raise capital on reasonable terms to meet its capital spending requirements. These witnesses further discuss the importance of strong investment-grade credit ratings in light of this period of extreme turmoil within the financial sector, and the critical role that the regulatory authorities play in achieving this result.

Many utilities are deferring capital expenditures whenever possible, with the potential for a shortfall in supply and renewable requirements when the economy begins to recover. Although we have taken steps to pare back our immediate capital spending, we cannot negatively impact our ability to provide service, either now or when the economy begins recovering.

IV. STEPS DUKE ENERGY CAROLINAS IS TAKING TO MEET THESE CHALLENGES

Q. WHAT MAJOR STEPS IS DUKE ENERGY CAROLINAS TAKING TO ADDRESS ITS FINANCIAL CONDITION AND FINANCING NEEDS IN THE MIDST OF THE FINANCIAL CRISIS?

A. We are taking a number of actions to weather this financial crisis while still moving forward with needed capital investments. First and foremost, we are committed to maintaining a strong balance sheet and maintaining our credit quality. We are also committed to maintaining our dividend.

We have also reworked our capital budget so as to defer certain planned capital expenditures, without harming our ability to provide high quality reliable service. And, we are very focused on controlling our O&M costs – toward that end, we have even temporarily frozen the salaries of a majority of our exempt employees, and we have established an aggressive internal cost control stretch goal to reduce O&M expenses across Duke Energy as a whole by $100 million . These measures will help diminish the increase in O&M costs for 2009 over 2008.

Q. WHAT ACTIONS IS DUKE ENERGY CAROLINAS TAKING TO ADDRESS THE OTHER MAJOR CHALLENGES FACING THE INDUSTRY?

A. Greenhouse gas regulation is the fulcrum of all the major challenges we face. In order to try and shape a constructive outcome on this overarching issue, we have been very active in advocating for reasonable emission reduction requirements, reasonable compliance timeframes, and fair and equitable allocations of allowances. For example in 2007 and 2009, our Chairman and CEO, Jim Rogers, provided testimony to both the U.S. Senate and the U.S. House of Representatives on the subject of greenhouse gas regulation.[4] In each of these instances, Mr. Rogers emphasized how important it is for the economy and for customers that we "get carbon legislation right." For example, he emphasized:

> - Sound climate change legislation should be based on three equal tenets – protecting our environment, protecting the economy, and protecting consumers from unacceptably high price increases.
> - To address climate change, we must have a bridge to a low-carbon economy. To cross that bridge, we have advocated for many years that we need an economy-wide cap and trade program for CO2.
> - A cap and trade program with appropriate allocation of allowances will minimize regional disparities and protect consumers as we develop technologies to reduce carbon dioxide emissions.
> - Some have suggested that allowances should be auctioned. But an auction approach would unfairly and disproportionately harm regions that depend on coal – especially the 25 states in the Midwest, Southeast and Great Plains.
> - Forcing customers from these regions to bear the cost of buying allowances for existing plants, while at the same time bearing the cost of retrofitting and replacing existing plants – would result in a double hit, paying twice for the bridge. Also, it would be counterproductive to the long term goals of climate change legislation.
> - Ensuring that electric customers are treated fairly and not burdened with unnecessary cost increases is a mission from which we will not retreat.

We have also worked diligently with stakeholders within and outside of our

[4] June 28, 2007 testimony before the U.S. Senate Environment and Public Works Committee; April 22, 2009 testimony before the U.S. House of Representatives Committee on Energy and Commerce; May 19, 2009 testimony before the Committee on Foreign Relations.

industry to advocate on behalf of our customers for policies that provide a pragmatic pathway to achieve aggressive environmental goals in a responsible and economically sustainable manner. Our advocacy and diligence on these issues is illustrated by the positions of the U.S. Climate Action Partnership (see Trent Exhibit 1 to my testimony) and the Edison Electric Institute's "Global Climate Change Points of Agreement" (see Trent Exhibit 2 to my testimony).

Because greenhouse gases will be regulated in the near future, we have been equally active in preparing for a carbon-constrained future. Not only will carbon regulations require substantial changes to our generation portfolio, electrification of transportation and other sectors may shift emissions to the power sector, creating further pressure for emissions reductions in our sector. Toward that end, we are incorporating carbon scenarios in our integrated resource plans, pursuing new nuclear generation options, new renewable resource options, aggressive energy efficiency efforts, and plans for the deployment of smart grids.

Q. PLEASE ELABORATE ON THE STEPS DUKE ENERGY CAROLINAS IS TAKING IN THE AREAS OF DEVELOPING NEW GENERATION, DEVELOPING MORE RENEWABLE SUPPLY SOURCES, ENERGY EFFICIENCY, AND SMART GRIDS.

A. With regard to the development of new generation, in the near-term we are focused on completion of the Cliffside advanced coal plant, which as of the end of the quarter ending March 31, 2009, was approximately 35% complete. This plant will significantly contribute to the replacement of over 1,000 MWs of older, less efficient, higher emitting coal plants. As we retire older coal units and take other actions, we expect this plant to effectively be carbon-neutral by 2018.

We are also preparing to start construction of two 620-MW combined cycle natural gas fired plants at two existing sites in North Carolina. Expected to be completed in 2012, these new plants will allow retirement of about 250 MWs of older coal-fired units (part of the 1,000 MWs referenced above). And, we continue to pursue the development of a new nuclear plant, Lee Nuclear Station in South Carolina.

With respect to bringing more renewable energy resources online, we have taken a number of steps in the Carolinas, such as:

- Issuing RFPs seeking bids for power generated from solar, wind, biomass and other renewable resources – we have signed contracts with two of the bidders and are actively negotiating with several more bidders at this point.
- One of these contracts is a 20-year agreement to purchase the full output of what will be one of the nation's largest photovoltaic solar farms, to be built in North Carolina. We expect that the facility will achieve full generation capacity in the spring of 2011.The second of these contracts involves a commitment to purchase the output of electricity generated from a 2.1 MW capacity landfill gas facility from a landfill in Durham, North Carolina.
- Actively negotiating with and purchasing energy and renewable energy certificates ("RECs") from suppliers presenting proposals outside the RFP process. In an effort to encourage additional unsolicited renewable bids, the Company developed a standard unsolicited proposal template and a standard REC purchase offer.
- Continuing to pursue the development of a rooftop solar program in our North Carolina service territory.

In the area of energy efficiency, we continue to pursue innovative approaches, such as our modified save-a-watt approach, to achieve more robust energy efficiency impacts so that we can reduce our demand and energy needs, and our carbon footprint, while at the same time lowering participating customers' bills.

We continue to work on upgrading and modernizing our distribution grids. As discussed by Witness Turner, initial smart grid deployments are underway in both North Carolina and South Carolina, with over 11,000 smart meters currently deployed. We are using these deployments to assess our installation techniques, test remote meter reading capability, and test our IT system's ability to process the substantial amounts of new data. Under the Residential Energy Management System pilot recently approved by the Commission we are also beginning to test in-home energy information and management systems in the South Charlotte deployment area.

Lastly, the potential advent of plug-in hybrid electric vehicles ("PHEVs") may profoundly affect the transportation sector and has implications for electricity usage patterns and grid operations. In order to help shape plans and policies for development of PHEVs and vehicle charging infrastructure in our service territory, Duke Energy Carolinas is working in collaboration with automakers, non-profit organizations, industry organizations and our neighboring utilities to address issues concerning market structure; technical and process standards; and consumer education and outreach. We are also supporting proposals by automakers to receive stimulus funds under the American Reinvestment and Recovery Act of 2009 to fund pilot programs for PHEV deployment in the Carolinas.

V. <u>MITIGATING THE IMPACT OF RATE INCREASES ON OUR CUSTOMERS</u>

Q. WHY IS DUKE ENERGY CAROLINAS SEEKING A RATE INCREASE IN THE MIDST OF A RECESSION?

A. Duke Energy Carolinas' requested rate increase is both justified and necessary. First, as we demonstrate, we have made prudent and reasonable investments in order to continue to provide high quality and reliable electric utility service to our customers, and without rate relief, we will not be able to earn reasonable returns for our investors. Second, without rate relief our credit quality may decline, which in turn could imperil our access to much needed capital on reasonable terms. Although we would prefer not to have to seek a rate increase in this environment, the consequences of not protecting our credit quality could well be much more harmful to our customers in the long run.

Q. WHAT SHORT-TERM STEPS IS THE COMPANY TAKING TO MITIGATE THE IMPACT OF THIS RATE INCREASE ON ITS CUSTOMERS?

A. With regard to this specific rate increase application, given the current severe economic recession we have taken two very important steps to mitigate the impact upon our customers. First, the Company is proposing that for this case only its new base rates be calculated using a lower return on equity than the Company's actual cost of equity. As the testimony of Dr. Vander Weide indicates, the Company's required return on equity is 12.3%. The Company fully supports Dr. Vander Weide's analysis and his return on equity opinion. Nevertheless, as a rate mitigation measure, the revenue requirement and resulting rates we request in this case are calculated using a return on common equity of 11.5%, which of course is less than 12.3%. As Dr. Vander Weide and other witnesses point out, the Company faces significant capital expenditure needs, along with increased financial risk in attracting the required capital to meet those needs. We believe the financial markets will look closely at the results in this case, and will expect to see some recognition of the Company's future capital needs and this increased financial risk. Accordingly, although we propose in this case that the Commission approve a return on common equity of 12.3% in recognition of the Company's capital requirements and risk profile, the Company is willing to accept a level of revenues that will produce only an 11.5% return on equity. We believe that this approach will send a positive signal to the financial community that this Commission is not ignoring the Company's future capital needs and risks, while at the same time mitigating the impact of this rate increase on customers.

Second, the accounting and pro forma adjustments to the test period do not include the typical inflation adjustment designed to reflect the higher level of costs that are anticipated to be known and measurable at the time of the hearing in this case. By taking on the risk of managing these inflationary pressures, this action reflects both the Company's aggressive cost control goals, and its desire to mitigate the impact of its rate increase on its customers during this significant recession. In light of this desire, Duke Energy Carolinas is willing to accept this level of revenues and the risk of not earning the allowed return on equity until a future rate proceeding.

As I also mentioned, we have deferred some capital expenditures, and we are committed to maintaining our credit quality and our access to both debt and equity capital on as reasonable terms as possible, all of which translate to lower costs and lower rates for customers. The testimony of Witnesses DeMay and Turner discuss these topics in further detail.

Finally, it is important to recognize that our rates are, and will continue to be, among the lowest in the nation, and among the lowest in the region. In my view, keeping our rates competitive and our service quality and reliability high, while at the same time keeping our Company on financially sound footing, is the best course of action for both our customers and our investors in the short-term and over the long term.

Q. WHAT LONGER-TERM STEPS IS THE COMPANY TAKING TO HELP CUSTOMERS MANAGE THEIR ENERGY COSTS?

A. In light of the many challenges our industry faces, particularly carbon regulation and the anticipated cost impacts associated with that, we continue to redefine the role and the boundaries of what it means to be an electric utility in the 21st century. We view our role as broader than operating power plants, and transmitting and distributing electrons, as important as those activities are. While those remain our core functions, in order to meet the challenges ahead of us and remain cost-competitive and value-competitive for our customers, we need to partner with our customers to help them manage their energy costs, through the investment in smart grid technology and energy efficiency, as well as in traditional and non-traditional power sources. We need to deliver reliable, affordable, and clean energy, *and* create value for our customers in new ways, such as helping them optimize their energy use.

Q. WHY IS IT IMPORTANT THAT THE COMMISSION GRANT DUKE ENERGY CAROLINAS THIS RATE INCREASE AND APPROVE ITS OTHER PROPOSALS IN THIS CASE?

A. As I discussed above, since its last rate case, Duke Energy Carolinas has made substantial capital investments in generation, environmental compliance, transmission, and distribution assets that are being used to provide high quality, reliable, and efficient electric utility service to our customers. Due in part to the operation of "regulatory lag" – the inevitable lag that occurs between the time a utility makes investments and the time that those investments are reflected in rates through an historical test year general rate case – these investments are not reflected in Duke Energy Carolinas' current rates. As a consequence, Duke Energy Carolinas' current rates are not providing sufficient revenues for the company to meet its day to day operating expenses and also provide its investors with reasonable returns on their investments of needed capital.

By traditional regulatory metrics, rate relief is needed and justified. As importantly, if we are going to successfully meet the challenges that lie ahead, it is imperative that our Company continue to receive constructive regulatory support, in the form of timely rate relief, and a willingness to be open to innovative and flexible approaches to managing the many new challenges our industry faces. To meet these challenges while maintaining our financial integrity and access to needed capital, we will need to collectively consider ways in which we can reduce regulatory lag, provide greater assurance of cost recovery to investors, and embrace constructive redefinitions of the roles that utilities can play in achieving clean, reliable and efficient energy production for the 21st century. Continued constructive regulation from this Commission will play an important role in our ability to successfully meet these challenges and continue to provide value for both customers and investors.

VI. <u>OTHER WITNESSES</u>

Q. HOW IS THE REST OF THE COMPANY'S FILING ORGANIZED?

A. In addition to me, our witnesses include:

1. **Brett C. Carter**, President of Duke Energy Carolinas, who will discuss Duke Energy Carolinas' operational, customer service and rate issues from a policy basis.

2. **James L. Turner,** President and Chief Operating Officer of Duke Energy's U.S. Franchised Electric and Gas operations and officer of Duke Energy Carolinas, who will discuss the performance of Duke Energy Carolinas' fossil and hydroelectric generation fleet and power delivery system; discuss the key drivers that impact operations and maintenance for the fossil/hydro fleet and the power delivery system. In addition, Mr. Turner explains the need for continued investment in the fossil/hydro fleet and power delivery system in order to continue to maintain system reliability in light of increasing environmental pressures.

3. **Dhiaa M. Jamil,** Group Executive and Chief Nuclear Officer, who will discuss the operational performance of Duke Energy Carolinas' nuclear generation fleet. He will also discuss the purchase of a portion of Saluda River Electric Cooperative, Inc.'s interest in the Catawba Nuclear Station and other capital additions since the 2007 rate case and key cost drivers and challenges impacting nuclear operations.

5. **Stephen G. De May**, Senior Vice President, Treasurer and Chief Risk Officer, who will address credit quality and the Company's capital structure and cost of debt. He also will discuss the Company's credit

ratings, the forecast of the Company's capital needs and conclude with a discussion of Duke Energy Carolinas' financial objectives.

6. **Steven M. Fetter,** President of a consulting firm named REGULATION UnFETTERED, former Chairman of the Michigan Public Service Commission and former head of the Fitch, Inc.'s utility ratings practice, who will discuss the perspective of investors with respect to credit ratings, regulatory environment, and return on equity for Duke Energy Carolinas in the context of the current rate case.

7. **Dr. James Vander Weide**, Research Professor of Finance and Economics at the Fuqua School of Business at Duke University, who will present his independent analysis of the fair rate of return on equity that allows Duke Energy Carolinas to attract capital on reasonable terms.

8. **J. Danny Wiles**, Vice President, Franchised Electric and Gas accounting, who will discuss the financial position of Duke Energy Carolinas at December 31, 2008 and actual results of the Company's operations for the calendar year ending December 31, 2008, which is the test period for this filing. He also will address our nuclear decommissioning costs recorded in the test year and a lead-lag study prepared for this case.

9. **John J. Spanos**, Vice President of the Valuation and Rate Division of Gannett Fleming, Inc., who will present his independent analysis of the depreciation study he conducted for Duke Energy Carolinas.

10. **Phillip O. Stillman**, General Manager, Regulatory Accounting and Planning, who will support the allocation of total company revenue requirements to the North Carolina retail jurisdiction and to each customer

class. In addition, he will support the accounting adjustments necessary to annualize and normalize test period expenses.

11. **Jane L. McManeus**, Director, Rates, who will support the base fuel factor which the Company has proposed as required by N.C. Gen. Stat. §§ 62-133 and 62-133.2(f). In addition, she will support the accounting adjustments necessary to annualize and normalize test period revenues.

12. **Carol E. Shrum**, Vice President, Rates, who will discuss the results of Duke Energy Carolinas' operations under present rates on the basis of an adjusted historical test period using the twelve months ended December 31, 2008. Ms. Shrum will discuss the additional revenue required as a result of the cost increases since the Company's last general rate case. In addition, she discuss several adjustments to the end of year rate base.

13. **Jeffrey R. Bailey**, Director, Pricing Design and Analysis, who will discuss the Company's proposed rate design and tariffs. He will also describe the proposed changes to the retail tariffs, and he will quantify the effects of those changes on our customers. Additionally, he will discuss the Company's proposal for changing rate tariffs over time to assure equitable cost allocations between customer classes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Summary Overview: USCAP Blueprint for Legislative Action

USCAP
United States Climate Action Partnership

On January 15, 2009, the US Climate Action Partnership (USCAP) issued the *Blueprint for Legislative Action* – a detailed framework for legislation to address climate change.

The *Blueprint* represents two years of work by USCAP members building on our January 2007 *Call for Action*, a groundbreaking report containing principles and recommendations that urged "prompt enactment of national legislation in the United States to slow, stop and reverse the growth of greenhouse gas (GHG) emissions over the shortest time reasonably achievable."

The *Blueprint* is a direct response to requests by federal policymakers for a detailed consensus that could help inform legislation. While USCAP is a diverse organization, it does not include all stakeholders and we acknowledge that the *Blueprint* is not the only possible path forward. However, we believe the *integrated* package of policies we are recommending provides a pragmatic pathway to achieve aggressive environmental goals in a responsible and economically sustainable manner.

The United States faces an urgent need to reinvigorate our nation's economy, enhance energy security and take meaningful action to slow, stop and reverse GHG emissions to address climate change.

USCAP agrees that the science is sufficiently clear to justify prompt action to protect our environment. Each year of delayed action to control emissions increases the risk of unavoidable consequences that could necessitate even steeper reductions in the future, with potentially greater economic cost and social disruption.

> *"Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea level."*
>
> Intergovernmental Panel on Climate Change, *Climate Change 2007: Synthesis Report*

To address these challenges successfully will require a fundamental shift in the way energy is produced, delivered and consumed in the US and around the globe. Thoughtful, comprehensive and tightly linked national energy and climate policy will help secure our economic prosperity and provide American businesses and the nation's workforce with the opportunity to innovate and succeed.

While we recognize that achieving the needed emission reductions is not free of costs, we also believe well-crafted legislation can spur innovation in new technologies, help to create jobs, and increase investment and provide a foundation for a vibrant, low-carbon economy.

International Principles

Climate change presents a global problem that requires global solutions. USCAP believes that international action is essential to meeting the climate challenge. U.S. leadership is essential for establishing an equitable and effective international policy framework for robust action by all major emitting countries. For this reason, action by the U.S. should not be contingent on simultaneous action by other countries. In our Blueprint we offer a set of principles to guide Congress and the Administration to address the global dimension of this problem.

Cap-and-Trade System Design

We believe the strongest way to achieve our emission reduction goals is a federal cap-and-trade program coupled with cost containment measures and complementary policies for technology research, development and deployment, clean coal technology deployment, lower-carbon transportation technologies and systems, and improved energy efficiency in buildings, industry and appliances. In a cap-and-trade system, one allowance would be created for each ton of GHG emissions allowed under the declining economy-wide emission reduction targets (the "cap"). Emitters would be required to turn in one allowance for each ton of GHG they emit. Those emitters who can reduce their emissions at the lowest cost would have to buy fewer allowances and may have extra allowances to sell to remaining emitters for whom purchasing allowances is their most cost-effective way of meeting their compliance obligation. This allows the economy-wide emission reduction target to be achieved at the lowest possible cost.

Targets and a Timetable for Action

USCAP believes the legislation should establish a mandatory, national economy-wide climate protection program that includes aggressive emission reduction targets for total U.S. emissions and for capped sectors (see sidebar). Equally important, it is imperative that the costs of the program be manageable. USCAP believes the recommended targets are achievable at manageable costs to the economy *provided that* a robust offsets program and other cost containment measures, along with other critically important policies as recommended in the *Blueprint* are enacted. In addition, Congress should require periodic assessment of emerging climate science and U.S. progress towards achieving emission reduction targets, and social, environmental and economic impacts in order to determine if legislative revisions are necessary to improve the nation's climate protection program.

Emission Reduction Targets

- 97%-102% of 2005 levels by 2012
- 80%-86% of 2005 levels by 2020
- 58% of 2005 levels by 2030
- 20% of 2005 levels by 2050

Scope of Coverage and Point of Regulation

USCAP recommends the cap-and-trade program cover as much of the economy's GHG emissions as politically and administratively possible. This includes large stationary sources and the fossil-based CO_2 emitted by fuels used by remaining sources. The point of regulation for large stationary sources should be the point of emission. The point of regulation for transportation fuels should be at the refinery gate or with importers. Congress should establish policies to ensure carbon-based price signals are transparent to transportation fuel consumers and other end users, thereby encouraging them to make informed GHG-reduction choices. Emissions from the use of natural gas by residential and small commercial end users can be covered, for example, by regulating the utilities that distribute natural gas, often referred to as local distribution companies (LDCs).

Offsets and Other Cost Containment Measures

Adequate amounts of offsets are a critical component of the USCAP *Blueprint*. Emissions offsets are activities that reduce GHG emissions that are not otherwise included in the cap. USCAP recommends all offsets meet strong environmental quality standards (i.e., they must be environmentally additional, verifiable, permanent, measurable, and enforceable). We recommend that Congress should establish a

Carbon Market Board (CMB) to set an overall annual upper limit for offsets starting at 2 billion metric tons with authority to increase offsets up to 3 billion metric tons, with domestic and international offsets each limited to no more than 1.5 billion metric tons in a given year.

In addition, the CMB should oversee a system-wide strategic offset and allowance reserve pool that contains a sufficiently large set of additional offsets and, as a measure of last resort, allowances borrowed from future compliance periods that could be released into the market in to prevent undue economic harm in the event of excessively high allowance prices, especially in the early years of the program. USCAP recommends other measures to limit allowance price spikes and volatility including unlimited banking of allowances and effective multi-year compliance periods.

Allocation of Allowance Value

Emission allowances in an economy-wide cap-and-trade system will represent trillions of dollars in value over the life of the program. USCAP believes the distribution of allowance value should facilitate the transition to a low-carbon economy for consumers and businesses; provide capital to support new low- and zero-GHG-emitting technologies; and address the need for humans and the environment to adapt to climate change.

USCAP recommends that a significant portion of allowances should be initially distributed free to capped entities and economic sectors particularly disadvantaged by the secondary price effects of a cap and that free distribution of allowances be phased out over time.

The *Blueprint* identifies principles to guide the fair and equitable allocation of allowances to: end-use consumers of electricity, natural gas, and transportation fuels; energy intensive industries that face international competition; trade-exposed commodity products; competitive power generators and other non-utility large stationary sources; low-income consumers and workers in transition; programs to achieve technology transformation; and adaptation needs of vulnerable people and ecosystems at home and abroad. A significant portion of emission allowance value should also be allocated to electric and natural gas LDCs, which are cost regulated, to dampen the price impact of climate policy on electricity and small natural gas customers, particularly in the early years of the emission constraint.

Credit for Early Action

USCAP recommends a robust program to provide credit for early action for those who have or will take early actions to reduce emissions. This is an important cost-containment mechanism for early actors to ensure they will not be at a relative disadvantage compared with those who wait to take action.

Complementary Measures

USCAP believes that policies and measures that are complementary to a cap-and-trade program are needed to create incentives for rapid technology transformation and to ensure that actual reductions in emissions occur in capped sectors where market barriers and imperfections exist that prevent the price signal from achieving significant reductions.

Technology Transformation

A robust technology transformation program that results in substantial investment in new technologies is a critical complementary measure to a national strategy to cap and reduce GHG emissions. USCAP recommends a program that features federal support for emerging technology research and early demonstration and deployment of new technologies.

Coal Technology

USCAP recommends that Congress provide needed regulatory certainty and substantial financial incentives to facilitate and accelerate the early deployment of carbon capture and storage (CCS) technology, including addressing financial and regulatory barriers that could delay wide-spread deployment. USCAP recommends implementing CO_2 emissions standards for coal plants initially permitted after January 1, 2015, subject to Congress providing adequate funding for CCS and needed regulatory certainty being in place; and retrofit requirements for coal plants initially permitted after January 1, 2009 and prior to January 1, 2015, subject to deployment thresholds being met.

Transportation

Achieving the USCAP economy-wide emission reduction targets and timetable will require a systematic approach that involves fuel providers, vehicle and equipment manufacturers, consumers and other end users, and public officials who set policy direction and plan and manage transportation and related infrastructure and land use. The systematic approach recommended by USCAP includes improving both fuel and vehicle GHG performance standards, as well as improving the efficiency of the transportation system.

Buildings and Energy Efficiency

USCAP believes one of the most immediate steps Congress can take to begin to address climate change is to enact policies and measures that improve the energy efficiency of the U.S. economy. We recommend aggressive promotion and implementation of GHG reduction programs including state- or utility-sponsored conservation and efficiency programs, tightened building codes and standards, and appliance efficiency standards. Collectively, these programs will help drive investment in cost-effective energy efficiency by encouraging utilities and consumers to improve efficiency when the cost of doing so is lower than the cost of an equivalent amount of energy in the form of electricity or natural gas.

Our Commitment

We, the members of the U.S. Climate Action Partnership, pledge to work with the President, the Congress, and all other stakeholders to enact an environmentally effective, economically sustainable, and fair climate change program consistent with our principles at the earliest practicable date.

To learn more about the USCAP *Blueprint for Legislation Action*, please visit www.us-cap.org.

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The U.S. Climate Action Partnership is a non-partisan coalition composed of 26 major corporations and five leading environmental organizations that have come together to call on the federal government to quickly enact strong national legislation requiring significant reductions of greenhouse gas emissions. USCAP has issued a landmark set of principles and recommendations to underscore the urgent need for a policy framework on climate change.

EDISON ELECTRIC
INSTITUTE

January 14, 2009

EEI Global Climate Change Points of Agreement

- EEI remains committed to working with Congress on enactment of legislation that will produce substantial emissions cuts and mitigate impacts to customers.
- EEI will focus its efforts on a cap-and-trade program, but also remain open to a tax-based or hybrid approach in the event the political environment shifts.
- Consistent with EEI's support for economy-wide programs, there should be no exemptions for any industry or specific fuel.
- EEI will aggressively pursue legislative and regulatory policies in support of climate-friendly technologies.
    - Efficiency and renewables are key to near-term reductions.
    - Maximizing new nuclear is key to mid-to-longer term reductions.
    - The aggressive development and deployment of carbon capture and storage coupled with advanced coal technologies are necessary to preserving the coal option.
    - Plug-in hybrid electric vehicles (PHEVs) and electric vehicles (EVs) can make a major contribution to reducing net GHG emissions, as well as to reducing foreign oil dependence and consumer prices at the pump.
    - Other no and low-emitting carbon technologies should be pursued (*e.g.*, smart grid).
    - Support key concepts underlying the Boucher CCS bill.
- Long-term targets (*e.g.*, 2050) should be set at an 80% reduction below current levels.
- Interim targets should be aligned with technology availability.
    - Near-term targets should be set and driven by efforts on energy efficiency, renewable energy, and, to some extent, new nuclear.
    - Medium-term targets should be set in the 10 – 20 year timeframe after enactment to match up with and enable technology development (*e.g.*, new nuclear, CCS, *etc.*).

- Cost-containment provisions should include a price collar, which would include a firm price floor and firm price ceiling. The collar should be based on the following principles:
    - Start narrow and gradually expand over time as technologies become available.
    - Simplicity of administration and transparency on use of revenue (which should include funding technology development and limiting economic impacts).
    - Formulaic (*i.e.*, easy to determine price for any point in time).
- Offsets also are an important cost containment mechanism that should be allowed to the maximum extent practical, subject to monitoring, measurement, appropriate third-party verification and regulatory oversight.
- State climate policies should be harmonized with federal climate policy, and states can pursue related programs (*e.g.*, energy efficiency programs, renewable portfolio standards, *etc.*). There should not be multiple cap-and-trade programs for GHG reductions.
- There also should be harmonization at the federal level. A single comprehensive federal climate law, rather than a regulatory regime consisting of multiple, overlapping or conflicting statutes, is called for.
- Under a federal GHG cap-and-trade program, allowances should be transferred to the power sector from the oil and gas sector as the market share of PHEVs and EVs increases.
- The best way to mitigate impacts on customers is to flow-through the benefits of allowances to customers. This can best be achieved by having allowances for regulated utilities allocated at the LDC level—a process that would be overseen by the state utility regulators—with appropriate adjustment to address impacts on unregulated generators.
    - Allowances should be allocated in the early years of a climate program, with a gradual transition to a full auction.
    - The initial allocation to the electric power sector should be consistent with its level of CO_2 emissions (*i.e.*, 40%).
    - Sector allowances should be allocated as follows: merchant coal generation would receive allowances equal to 50% of base-year emissions (because it is assumed both that the other 50% is recovered by gas being on the margin in competitive markets and that gas has, on average, 50% of the carbon content of coal), with the balance of allowances allocated to LDCs based on an even split between base-year emissions (including emissions associated with purchased power) and retail sales. This approach is referred to as the "50-50-50" proposal.

EDISON ELECTRIC INSTITUTE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	BRETT C. CARTER
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brett C. Carter, and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CAROLINAS, LLC?

A. I am President of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "the Company"). Duke Energy Carolinas is a subsidiary of Duke Energy Corporation ("Duke Energy").

Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.

A. I am a graduate of Clarion University in Pennsylvania with a Bachelor of Science degree in Accounting. I also have a Master of Business Administration degree, with a concentration in Marketing, from the University of Pittsburgh and have completed the Harvard Business School's Advanced Management Program. I am a member of the board of directors and serve as chair of the Business Development Committee for the Crisis Assistance Ministry of Charlotte. I serve on the North Carolina State Ports Authority Board. I am also a member of Leadership Charlotte.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy in 2005 as vice president of residential and small business customers for the Duke Power division (now known as Duke Energy Carolinas) and was also responsible for marketing strategy and operations of the Customer Service Center. I then served as vice president of call center operations for Duke

Energy's U.S. Franchised Electric and Gas organization. Before becoming president of Duke Energy Carolinas, I most recently served as senior vice president of customer service and business development for Duke Energy supporting all of the company's utility operating companies, including Duke Energy Carolinas. Prior to joining the company, I served as vice president of the central services division for Aquila Energy Corp. in Kansas City, Missouri.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I lead Duke Energy Carolinas; Duke Energy's regulated electric utility business operating in North Carolina and South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is: (1) to provide a brief description of Duke Energy Carolinas' operations and operating performance; (2) to summarize what the Company is requesting in this proceeding; (3) to explain why the relief we request is important to our ability to continue to provide safe, reliable and economically priced electric service to our customers, while at the same time building the electric infrastructure we need to comply with current and anticipated environmental and other regulatory requirements and ensuring adequate resources to meet customer demand; and (4) to discuss the impact of the Company's economic development activities and explain why they are vital to our customers, the State of North Carolina and the Company.

II. DUKE ENERGY CAROLINAS' ELECTRIC UTILITY SYSTEM AND OPERATIONS

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY CAROLINAS' ELECTRIC UTILITY SYSTEM AND OPERATIONS.

A. Duke Energy Carolinas is North Carolina's largest electric utility, in terms of the number of retail customers served, the size of our service territory, the size of our power production system, and the size of our transmission and distribution system. In 2008, we provided retail electric service to approximately 2.4 million retail customers throughout a 24,000 square mile service territory in the Central and Western portions of North Carolina and Western South Carolina. Approximately 1.8 million of our retail customers are in North Carolina. Our retail customers include residential, commercial, institutional, governmental and industrial customers. Manufacturing continues to be the largest contributor to the economy in our region, with the rubber and plastic products, chemicals, paper products, and automotive industries also being of major significance to our service territory's economy. Textile manufacturing, while continuing to decline, still plays a significant role in our region, as do the real estate and education services sectors. The major North Carolina cities in our territory include Charlotte, Durham, Winston-Salem and Greensboro.

To generate the power to serve these customers, Duke Energy Carolinas owns and operates three nuclear generating stations (two owned outright and one, as indicated below, owned partially), eight coal-fired generating stations, thirty hydroelectric stations, and several gas-fired combustion turbine generating stations. On September 30, 2008, Duke Energy Carolinas completed the purchase of a portion of Saluda River Electric Cooperative, Inc.'s ownership interest in Catawba Nuclear Station. Following the closing of this transaction, Duke Energy Carolinas owns approximately 19% of the Catawba Nuclear Station. Altogether, these generating facilities are capable of producing approximately 19,000 megawatts ("MWs") of electricity. The Company also makes long-term and spot market purchases of electricity to assure economical and reliable service to our customers. The testimony of Company Witnesses Turner and Jamil provides further detail on our power supply resources.

To transmit and distribute this power Duke Energy Carolinas owns and/or operates approximately 13,000 circuit miles of transmission lines, over 1,600 substations, over 100,000 miles of distribution lines, and is interconnected with eight other electric utilities. Witness Turner's testimony provides additional detail on our power delivery operations.

Duke Energy Carolinas' headquarters is located in Charlotte. In addition, the Company has 41 operations centers throughout our service territory from which we provide service to our customers, and approximately 130 payment locations at which customers can pay their bills.

III. DUKE ENERGY CAROLINAS' OPERATIONAL PERFORMANCE AND CUSTOMER SATISFACTION

Q. WHAT ARE DUKE ENERGY CAROLINAS' GOALS WITH RESPECT TO OPERATIONAL PERFORMANCE AND CUSTOMER SATISFACTION?

A. Our goal is to deliver dependable, reliable, safe and efficient electric utility service at reasonable prices. Our continuing challenge is to be a leader in the nation in electric utility operational performance, measured in terms of the safety and reliability of our service and customer satisfaction, while also keeping our cost of operation low in the face of new capital investment needs and increasingly costly environmental and other regulatory requirements.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' PERFORMANCE IN TERMS OF THE RELIABILITY, EFFICIENCY, AND SAFETY OF ITS ELECTRIC OPERATIONS.

A. Duke Energy Carolinas continues to perform extremely well in numerous key areas. Witnesses Turner and Jamil describe the efficiency of our generating fleet and Witness Turner also discusses the reliability of our transmission and distribution system. In addition to our low cost production, transmission and distribution of power and our reliable power plant and transmission and distribution system performance, we consistently deliver high quality customer service, as I discuss in greater detail below.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' PERFORMANCE IN TERMS OF PROVIDING HIGH QUALITY CUSTOMER SERVICE.

A. Customer satisfaction is very important to us. We respond to our customers' inquiries and needs from two call centers employing approximately 300 customer service representatives, along with utilization of third party vendors. We handle more than 10 million calls annually through automated and live voice channels, ranging from service orders, to requests for billing and payment information, to electric trouble calls. In 2008, our Southeast call center handled 76% of its calls within 30 seconds or less, and was able to resolve the vast majority of calls correctly the first time, with no follow-up calls required for the customer. The performance of our customer service representatives is monitored on an ongoing basis by call center supervisors.

To further enhance customer service, the Aclara Agent Desktop & Online Services Tool was implemented in 2008. The energy analysis tool provides a standardized, customer-friendly method for customers to resolve energy usage and cost inquiries and address billing concerns. This tool improves the customer experience by providing individualized information, alternatives and specific energy efficiency options to help customers improve their understanding of energy usage and reduce future bill amounts. Access of the tool by North Carolina customers since its launch in August 2008, has averaged over 250,000 log-ins per month.

We serve our large customers in a variety of ways including using business relationship managers that have assigned customers to serve, a business service center that is designed to handle routine requests, and a dedicated website for large business customers called "My Duke Energy." Important measures of customer satisfaction with our performance are national benchmark studies conducted by third parties. For 2008, Duke Energy as a whole ranked fourth in the nation in TQS Research, Inc.'s Key Accounts National Benchmark study. Duke Energy Carolina contributed to this excellent ranking with an overall customer satisfaction score of 91.7% compared to the nationally top ranked utility which had an overall customer satisfaction score of 91.3%. This study gauges the satisfaction of our largest customers - manufacturers with at least 3 MW in annual demand, large hospitals and large universities - in several areas, including overall satisfaction, reliability, price, power quality and account management. The

Company has placed in the Top 10 of this study for 10 consecutive years. Another important measure of our success in this area is the annual electric utility customer satisfaction studies conducted by J.D. Power and Associates ("J.D. Power"), a firm well known for setting the standard of consumer opinion and customer satisfaction studies in many key industries. That firm performs annual studies of electric utilities' residential and midsize business customer satisfaction. Duke Energy Carolinas participates in both of these annual studies, and the results indicate that we are doing an outstanding job of consistently providing high quality customer service.

The J.D. Power residential customer study, established in 1999, calculates overall customer satisfaction based on six performance areas: (1) corporate citizenship; (2) price; (3) power quality and reliability; (4) billing and payment; (5) customer service; and (6) communications. In the 10 years that the J.D. Power residential study has been conducted, Duke Energy Carolinas' scores in overall satisfaction have consistently outperformed the scores of the industry average and the South region average. For 2008, the most recent residential customer study, Duke Energy Carolinas ranked in the top quartile nationally and fourth in the South region of the United States for overall satisfaction. J.D. Power also conducts an annual survey of midsize business customers using the same six performance areas that are used in the residential study, and Duke Energy Carolinas has consistently exceeded the scores of the industry average and the South region average in overall satisfaction. In the 2008 study, Duke Energy Carolinas finished in the top quartile nationally and ranked sixth (out of thirteen) in the South region's Large segment category.

Q. TO WHAT DO YOU ATTRIBUTE DUKE ENERGY CAROLINAS' HIGH CUSTOMER SATISFACTION?

A. Since being named President of Duke Energy Carolinas, I have met with numerous key customers, customer groups, and other stakeholders. As I have travelled the state and met with our customers, again and again I have heard from customers that they are satisfied with our highly competitive rates, our reliability, our responsiveness, and with our partnering with them to improve the energy efficiency of their operations.

IV. DUKE ENERGY CAROLINAS' CURRENT AND PROPOSED RETAIL ELECTRIC RATES

Q. PLEASE DISCUSS DUKE ENERGY CAROLINAS' CURRENT RETAIL ELECTRIC RATES.

A. Our current retail electric base rates were established by the Commission in 2007, in Docket No. E-7, Sub 828.[1] The 2007 general rate case resulted in an overall average rate decrease of 5.5% in 2008 and an additional 2% decrease in 2009. Thus, even given the recent general rate case, Duke Energy Carolinas has not had a general rate increase since 1991. In fact, absent the 2007 rate reduction, the rate increase we would be proposing in this case would be less than 6%.

For the last 18 years, additional revenues from customer growth, coupled with operating efficiencies, low inflation, and a fuel adjustment clause, have allowed the Company and its customers to enjoy stable and highly competitive rates. In addition to the rate decreases resulting from our last general rate case, since 1991 our retail rates have been adjusted periodically to reflect changes in

[1] This docket was consolidated with Docket Nos. E-7, Sub 829 and Docket No. E-100, Sub 112.

fuel costs, as well as to implement other rate reductions. For example, in 2005, we reduced rates for all customers by approximately $106.3 million by offsetting fuel expense with certain accumulated deferred income tax liabilities. Additionally, we implemented an across-the-board one-year decrement to North Carolina retail rates of over $117.5 million to reflect a share of our projected five-year savings from the anticipated efficiencies from the Duke Energy merger with Cinergy Corporation in 2006.

Significantly, our North Carolina retail rates today are lower than our rates were eighteen years ago in real terms, i.e., when inflation is factored in. Also importantly, as Witness Trent has mentioned, Duke Energy Carolinas' current average retail electric rates compare very favorably to both national and regional average retail electric rates. According to information compiled by Edison Electric Institute ("EEI"), as of December 31, 2008, our North Carolina retail rates were 31% lower than the national average retail electric rate (as measured by average revenue per kWh), and 24% lower than the South Atlantic regional average retail rate on a per kWh basis. Even after giving effect to the proposed increase, our average rates will still be significantly lower than both the national average rates and the regional average rates.

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE RATE INCREASE DUKE ENERGY CAROLINAS PROPOSES IN THIS CASE AND WHY IT IS NEEDED.

A. Duke Energy Carolinas is seeking to increase its retail revenues by approximately $496 million which represents an overall 12.6% increase in rates. As Witness Trent explains, this rate increase is necessary to allow Duke Energy Carolinas to continue to provide safe, reliable and economically priced electricity to its customers and to continue to build the infrastructure necessary for North Carolina to continue to grow and transition to a carbon-constrained world. Over the eighteen-year period since our last general rate increase, we have been able to manage our costs in such a way that despite new capital additions and increased O&M costs, we have been able to hold our prices relatively steady, and below the rate of inflation. This is at a time when almost everything else our customers purchase has increased in price. As a result of significant capital investments in our system we now must increase our electricity prices in order to continue to meet our obligations to our customers and to our shareholders. It is important to keep in mind that even after our rates are increased, our prices will still be well below the national average and will still be lower than they were 18 years ago on an inflation adjusted basis.

There are certain major factors that make our proposed rate increase necessary: (1) our financial position will erode further if we continue to serve additional customers at today's costs while collecting revenues at rate levels which, on an inflation adjusted basis, are below our 1991 rates; (2) we need to reflect in our rates the significant capital investments we have made, for example, the addition of new generating plant and environmental control equipment and upgrades to our transmission and distribution systems, environmental, reliability, safety and regulatory compliance; (3) we must reflect in our prices the impact of general inflationary pressures on our cost of doing business; and (4) we need to maintain sufficient cash flow and credit quality to finance necessary capital expenditures on reasonable terms, especially important during this period of economic volatility.

Q. DESCRIBE THE SIGNIFICANT CHALLENGES DUKE ENERGY CAROLINAS FACES.

A. Our service territory covers an area of continuing population growth. Although we project a short-term reduction in load growth under the current economic conditions, the Company continues to experience residential growth and expects long-term growth in electric demand. Even with the major investments we have already made in our generating system, we face the need to add a substantial amount of new capacity (approximately 8,800 MWs by 2028). To address this challenge, we are pursuing energy efficiency as a "fifth" fuel in meeting customer demand, along with advanced nuclear, clean coal, natural gas and renewable energy. For example, we continue to pursue the development of the one new coal-fired Cliffside unit recently authorized by the Commission as well as a longer-term investment in a new nuclear generating station. We are also preparing to start construction of new gas fueled combined cycle units to meet the growing need for power in our service territory.

With the imminent prospect of climate change regulation and the need to replace aging plants, we need to modernize our generating system. Additionally, there is a need to continue to expand, upgrade and modernize our transmission and distribution systems to serve new customers and to enhance the reliability and functionality of our system, which will require significant capital investment.

Q. HOW HAS ONGOING INFLATION AFFECTED THE COMPANY'S COST OF SERVICE?

A. This proposed rate increase is driven more by rate base additions than by general inflationary pressures. Nevertheless, in addition to its effect on our construction costs and cost of fuel, inflation since our last general rate increase in 1991 has affected our wages and the costs of materials and supplies. This becomes obvious when you consider that in 1991 the consumer price index was at 136, while in 2008 it was at 215 - a 58% increase. Although the current recessionary period has dampened the extreme cost increases seen in the period 2006 though 2008, the many efficiencies we have achieved in our operations along with cost control measures and new revenues from adding new customers is no longer sufficient to offset the costs of significant rate base additions combined with these inflationary pressures. As other witnesses discuss, Duke Energy continues to look for opportunities to implement sustainable cost reduction measures; however, there is a limit to how much you can cut costs without affecting reliability and service quality, when capital expenditures and other cost increases are outpacing increased revenues from load growth.

Q. HOW DOES DUKE ENERGY CAROLINAS' COST OF SERVICE, AS PRESENTED IN THIS CASE, COMPARE TO THE COST OF SERVICE APPROVED BY THE COMMISSION IN 1991 IN THE COMPANY'S LAST GENERAL RATE INCREASE?

A. Although Duke Energy Carolinas' capital investments in property, plant and equipment have increased substantially since our last general rate increase in 1991, driven by new generation, regulatory compliance, and other additions I have already discussed, the increase in current annual operating costs compares favorably to the inflation rate during that time period. This is due to intense and consistent management focus on costs. The table below summarizes how certain of Duke Energy Carolinas' major costs (and cost drivers) have changed over the last approximately 18 years. As the table shows, although the Company's investment in property, plant and equipment has increased substantially, our non-fuel O&M costs (other than depreciation and taxes) have increased only modestly over that period. In fact, on an inflation-adjusted per kWh basis, our non-fuel O&M costs (other than depreciation and taxes) have actually declined from the 1990 level (which is 2.39 cents per kWh when adjusted for inflation), , to 1.89 cents per kWh in 2008. The numbers shown below are constant nominal dollars -- *i.e.*, not adjusted for the effects of inflation:

Type of Cost (or Cost Driver)	**1990**	**2008**
Generating Capacity*	17,359 MWs	19,378 MWs
Property, Plant & Equipment*	$11.2 billion	$22.3 billion
KWH Sales (millions)	66,981	85,476
Peak Demand (MW)	14,046	16,888
Cost of Equity	12.5% (authorized)	11.0% (currently authorized) 12.3% (supported in this case)
Base Fuel Costs	1.1032 cents per kWh	2.3682 cents per kWh
Non-Fuel O&M Costs (excluding taxes and depreciation)	1.45 cents per kWh	1.89 cents per kWh
Average Number of retail Customers (NC and SC)	Approx. 1.6 million	Approx. 2.4 million

*Reflects closing of Bad Creek Pumped Storage facility as represented in the 1991 rate case, Docket No. E-7, Sub 487.

V. ECONOMIC DEVELOPMENT ACTIVITIES

Q. WHY DOES DUKE ENERGY CAROLINAS VIEW ECONOMIC DEVELOPMENT AS A VITAL PART OF ITS BUSINESS?

A. Duke Energy Carolinas has a long history of supporting the economic development of this State. Our first generating plants and transmission and distribution grid were built over a hundred years ago to fuel industrial development in the Carolinas. Our sales and profits are inextricably tied to the economic success of our service area. Recent history demonstrates this. The changing composition of the economies of North Carolina and South Carolina has resulted in significant losses of manufacturing jobs and business in the Company's service area. This in turn has negatively affected the Company's sales of electricity in North Carolina and South Carolina. For example, the Company's sales to industrial customers declined nearly 13% from 1990 to 2008. Further, the Company's sales to textile industries have declined over 10% *per year* since 2000. In response, Duke Energy Carolinas has initiated various programs to stimulate new industrial development in its service area, including its Economic Development and Economic Redevelopment Riders that offer credits for customers locating new load on the Duke Energy Carolinas system. Most of that effort has been aimed at encouraging new industrial investments. Through its previous BPM sharing mechanism, the Company sought to also help established industries and save jobs by providing some relief to its existing industrial customers.

In April, Duke Energy spearheaded the first Charlotte Energy Summit, along with the Charlotte Regional Partnership and the Charlotte Chamber of Commerce. With the objective of identifying ways to promote regional job growth in the energy sector and to position the region as a nationally recognized energy cluster, the summit addressed energy issues facing our state and region and was attended by over 120 senior-level executives representing over 50 energy-related companies from the Charlotte region. During workshops, representatives from nuclear, alternative energy, and energy services industries focused on ways to promote job growth. Resulting initiatives from the summit will continue moving forward – next on the list is the creation of an action plan based on the insight gathered during the summit.

We believe strongly that a healthy industrial base is good for all of our customers. A healthy and broad industrial customer base enables us to spread our fixed costs over a broader group of customers, thereby ensuring that prices are lower, on average, for all customers. Also, as new manufacturing businesses are established and existing manufacturing businesses expand, they typically create a significant multiplier effect that directly and indirectly produce additional jobs and investments. In light of the current economic downturn, our focus on economic development – targeted towards potential new and existing customers – is more important than ever to maintain the competitiveness of our region. We are confident that our continuing economic development efforts will continue to provide positive results here in North Carolina.

Q. PLEASE DISCUSS SOME OF THE RESULTS IN NORTH CAROLINA OF DUKE ENERGY CAROLINAS' ECONOMIC DEVELOPMENT ACTIVITIES.

A. Our support for state and local economic development efforts, combined with our competitive electric rates, has produced a number of North Carolina economic development successes in which Duke Energy Carolinas has played a part. In 2008 alone, we estimate that our cooperative efforts with state and local economic development officials have contributed to the creation of more than 3,200 North Carolina jobs and over $610 million of capital investment in North Carolina. Also in 2008, Duke Energy Carolinas was named one of the "Top 10 Best" utility economic development programs by *Site Selection* magazine, a recognition we earn regularly.

North Carolina's competitive advantages – a quality workforce, strong educational institutions, superior transportation infrastructure, and competitive energy rates – have been key factors in the state's ability to attract significant new businesses in the financial, electronics manufacturing, plastics, biopharmaceuticals, medical equipment, and automotive parts industries. These economic development successes continue to help offset the loss of jobs (and customers of Duke Energy Carolinas) in the textile industry.

VI. CUSTOMER ASSISTANCE PROGRAMS

Q. WHAT IS DUKE ENERGY CAROLINAS DOING TO ASSIST INDIVIDUAL CUSTOMERS, ESPECIALLY LOWER-INCOME CUSTOMERS, DURING THIS DIFFICULT PERIOD OF TIME?

A. Most importantly, we work hard to keep our costs under control and our rates competitive. Also very importantly, we recognize that one of the best ways we can help our customers who are struggling financially is to help them better manage their electric usage. Our new Low Income Energy Efficiency and Weatherization Assistance Program specifically targets low-income customers. In addition, the new Residential Energy Assessments, Residential Smart $aver®, and Power Manager programs recently approved by the Commission provide opportunities for residential customers of all income levels to reduce their monthly electric bills. For example, we estimate that by participating in appropriate energy conservation programs, the average North Carolina residential customer (using 1,000 kWh a month) can save about $5 per month, compared to the cost of the current energy efficiency rider of approximately $0.38 per month.

In addition to these newly approved energy efficiency programs, we are also exploring the potential for several new programs that target one of the most difficult to serve segments of our customer base, low income renters. These are typically some of the most difficult customers to reach via energy efficiency programs, because they do not own their homes, and they may not even be the customer who pays the energy bill directly. Yet many renters are also the customers who most need financial assistance right now. One such program is a multi-family energy efficiency solution research project under which Duke Energy Carolinas is evaluating opportunities to create value for both tenants and owners and overcome longstanding barriers to energy efficiency improvements in the non-subsidized rental market. The goal of this program is to lower tenant energy usage and cost while reducing the total cost of ownership for owners by evaluating different ownership options for equipment and appliances. Duke Energy Carolinas is exploring opportunities to use American Reinvestment and Recovery Act of 2009 competitive funds for this project.

We are also partnering with over 100 community assistance and other agencies across our service territory that receive public funds and private donations to provide emergency bill payment assistance to our customers. We have developed a special assistance agency website through which the Company interacts with these agencies and provides information they need to provide services to their clients. Through this website, partnering agencies will offer to complete a short energy survey with each customer. Duke Energy Carolinas will mail 12 compact fluorescent lamps to customers who participate in the energy survey. Moreover, the information collected in the energy survey will be used to better target additional efficiency services to these households.

The Company is also evaluating the potential to partner with local community and faith-based organizations to better reach low-income and elderly customers. The goal of this effort is to overcome awareness, trust and comprehension challenges prevalent in these segments by utilizing a face-to-face engagement approach to promote our efficiency services.

Duke Energy has also been aggressively pursuing partnership opportunities with state and local entities to fully leverage the combined impact of American Reinvestment and Recovery Act of 2009 weatherization program funds and our low-income weatherization program. Additionally, we are aggressively pursuing federal stimulus funds under that Act in areas involving smart grid technology and renewable energy technologies. To the extent we are successful in obtaining stimulus funding, these funds will offset our costs of providing service, to the benefit of all of our customers.

In addition to these initiatives, we currently offer a number of other programs designed to help customers lower or pay their electric bills. For example:

- The Company has contributed millions of dollars to the Special Needs Energy Products Loan Program. Under this program, administrative agencies selected by the Company administer the funds and provide low-interest or deferred loans to low income customers.

- Duke Energy's Foundation makes significant contributions to the Share the Warmth and Cooling Assistance and Fan Relief programs – a total of $1.2 million in 2008 and 2009 to date.
- Consistent with a 1978 Commission order, the Company continues to provide a discount on the first 350 kwh of usage each month for customers who are blind, disabled, or 65 years or older and that receive Supplemental Security Income from the federal Social Security Administration.

VII. <u>CONCLUSION</u>

Q. MR. CARTER, WHY IS IT IMPORTANT THAT DUKE ENERGY CAROLINAS BE GRANTED THIS RATE INCREASE?

A. A safe, reliable and economically priced source of energy benefits existing customers. It also attracts new growth which benefits existing customers in terms of new jobs, new tax revenues and new opportunities. If we are to continue to carry out our obligation to provide safe, reliable and economically priced electricity to our customers and build the infrastructure to provide the energy for North Carolina's future growth, our revenues must cover all of our costs, including a return on investment that will enable us to raise on reasonable terms the large amounts of capital that the Company's plans call for. As Witnesses Trent, DeMay and Fetter testify, Duke Energy Carolinas must maintain a strong financial position as we enter this next era of large capital project requirements. This is particularly important during this period of financial recession and credit crisis. This rate increase is needed because our current rates will not accomplish that. Today, the Company's retail prices are well below the national average and they will remain so even with the requested rate increase. We have successfully managed our costs, capitalized on customer growth and achieved outstanding operational efficiencies since 1991 to avoid the need for a general rate increase. However, our costs, particularly those tied to capital investments; continue to increase beyond the incremental revenues from customer growth. We now must increase our electricity prices to meet our obligations to our customers and to our shareholders.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	JAMES L. TURNER
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY.

A. My name is James L. Turner and my business address is 526 South Church Street, Charlotte, North Carolina 28202. I am a Group Executive of Duke Energy Corporation ("Duke Energy") and President and Chief Operating Officer ("COO") of Duke Energy's U.S. Franchised Electric and Gas business. I am also an officer and director of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "Company").

Q. WHAT DO YOU MEAN WHEN YOU USE THE TERM "U.S. FRANCHISED ELECTRIC AND GAS BUSINESS?"

A. This term refers to the segment of Duke Energy that is comprised of our regulated utility operating companies in five states – Duke Energy Carolinas, Duke Energy Indiana, and Duke Energy Ohio and Duke Energy Kentucky. It is a functional business segment organized for operational and financial reporting purposes, but it is not a legal entity.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS PRESIDENT AND COO OF U.S. FRANCHISED ELECTRIC AND GAS?

A. I am responsible for all non-nuclear operations of our regulated utility operating companies, including Duke Energy Carolinas. This includes fossil-hydro generation operations, power delivery, gas distribution (Ohio and Kentucky only), customer service operations, fuel and portfolio optimization, wholesale business, new generation projects, supply chain, engineering and technical services, and environmental health and safety.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree from Ball State University and a Juris Doctor degree, cum laude, from the Indiana University School of Law. I also completed the Advanced Management Program at the Harvard Business School; the Leadership at the Peak Program at the Center for Creative Leadership; and the Reactor Technology Course for Utility Executives at Massachusetts Institute of Technology.

Prior to my present position, which I assumed in April, 2007, I served as President of U.S. Franchised Electric and Gas, where I was responsible for customer service, legislative and regulatory strategy, wholesale operations and economic development for each of Duke Energy's utility operating companies in the five states they serve. Prior to the merger of Duke Energy and Cinergy Corp. ("Cinergy"), I served as President of Cinergy. Before that, I was the Cinergy's Chief Financial Officer, where I was responsible for the company's financial operations, investor relations, corporate development, and strategic planning. I also served as Chief Executive Officer for Cinergy's regulated business unit.

Before joining Cinergy in 1995, I was employed as a principal in the Indianapolis law firm of Lewis & Kappes, P.C., representing industrial customers in state utility commission proceedings as well as before the Indiana General Assembly. Before joining Lewis & Kappes, I served as the Indiana Utility

Consumer Counselor from 1991 to 1993, leading a state agency responsible for representing all classes of Indiana consumers of electricity, natural gas, telephone, water and sewer services. In 1992, I served on the Executive Committee of the National Association of State Utility Consumer Advocates. I began my career as an attorney in the Indianapolis law firm of Bingham Summers Welsh & Spilman (now Bingham McHale) in 1984.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) describe how we strive to operate our business in a safe manner that appropriately balances three key attributes: reliability, affordability, and environmental stewardship; (2) describe Duke Energy Carolinas' fossil and hydroelectric generation fleet and power delivery system; (3) discuss the significant capital investments we have made since the 2007 rate case in the non-nuclear generating facilities and power delivery system serving our Carolinas' operations, with particular emphasis on the additions of environmental control and monitoring equipment in our fossil stations; (4) explain the need for continued investment in the fossil-hydro fleet and power delivery system in order to continue to maintain system reliability and compliance with environmental regulations; (5) discuss the operating performance of Duke Energy Carolinas' fossil-fueled and hydroelectric generating facilities and power delivery system during the test period; (6) discuss the key drivers that impact operations and maintenance for the fossil-hydro fleet and the power delivery system; and (7) describe the Company's efforts to control costs in these operations as well as the related challenges it faces.

Q. WHAT ARE DUKE ENERGY CAROLNAS' PRIMARY OPERATIONAL OBJECTIVES?

A. The primary objective of Duke Energy Carolinas' operations is to safely provide reliable and cost effective electric service to our customers in the Carolinas. This objective is consistent with our statutory obligation to provide efficient service at reasonable rates. In meeting this objective, we strive to operate our business in a manner that appropriately balances three key attributes: reliability, affordability, and environmental stewardship. This balance is critical because focusing on any one of these attributes to the exclusion of others could drive results that do not ultimately benefit our customers. For example, focusing solely on the cleanest generation sources may be great for the environment, but would also lead to reliability problems and rate shock; overspending on reliability without an emphasis on cost-effectiveness may come at the expense of affordability; and focusing solely on getting costs to the lowest possible level may result in decline in service quality and ill-equip the Company for the challenges of tomorrow. Therefore, in making its investment and operating decisions the Company must be mindful that such decisions are cost-effective in terms of current and anticipated regulation, customer requirements, and community expectations.

Q. YOU HAVE MENTIONED A COUPLE OF TIMES THE SAFE OPERATION OF YOUR SYSTEM. HOW DOES SAFETY PLAY A ROLE IN THE BALANCE THAT YOU SPEAK OF?

A. We think of safety as one of our first principles. Everything we do in operating our business is underpinned by a commitment to protecting public safety, but also to having our employees and the contractors who work on our premises return home safely to their loved ones every day. I am pleased to say that our safety record has improved significantly in the past several years and that 2008 was the safest year on record for Duke Energy. But this is an area where we can never be content. We must always strive to drive towards zero injuries and illness in the operation of our business.

II. FOSSIL-HYDRO GENERATION ASSETS AND OPERATIONS

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' FOSSIL-HYDRO GENERATION PORTFOLIO.

A. Duke Energy Carolinas' fossil-hydro generation portfolio consists of 14,032 megawatts ("MW") of generating capacity, made up as follows:

Coal-fired generation -	7,672 MWs
Hydroelectric -	3,218 MWs
Combustion Turbines -	3,142 MWs

(Combustion turbines can operate on natural gas or fuel oil)

This portfolio includes a diverse mix of units that, along with Duke Energy Carolinas' nuclear capacity, allow the Company to meet our customers' dynamic load requirements in a logical and cost-effective manner. As customer load has grown, a greater percentage of load has been served from the coal-fired units. In 2008, the nuclear units provided approximately 47% of Duke Energy Carolinas' total generation, the coal units provided 53%, and the hydroelectric system and the combustion turbines were available to provide critical peaking power.

Q. **WHAT FOSSIL-HYDRO RATE BASE ADDITIONS HAVE BEEN ADDED SINCE THE 2007 RATE CASE?**

A. The Company's Fossil-Hydro rate base additions fall into three categories: environmental additions, reliability improvements, and hydro relicensing projects. The most significant capital addition to the Company's Fossil-Hydro fleet since the 2007 rate case is the flue gas desulfurization equipment ("FGD" or "scrubber") at the Allen Steam Station. These two scrubbers serve all five units at the Allen plant and began commercial operation between February and May, 2009. This equipment is necessary to meet North Carolina's Clean Smokestacks Act sulfur dioxide ("SO_2") reduction requirements and has the capacity to reduce SO_2 emissions by greater than 95%. The direct capital cost associated with the Allen scrubbers is projected to be $502.8 million.

Additionally, in December 2008 we added selective catalytic reduction ("SCR") equipment at Marshall Unit 3 in support of various nitrogen oxide ("NO_X") control requirements, most notably the 8-hour ozone standard in the Charlotte region. The direct capital cost associated with the Marshall Unit 3 SCR equipment through March 31, 2009 is $101.4 million, and we expect to spend an additional $5.1 million on project close-out activities. This SCR equipment has the ability to reduce the NO_X emission rate for the unit by 80%. Other environmental projects such as coal combustion by-product ("CCP") landfill and dry storage, SCR catalyst additions and mercury monitoring requirements involved an additional $84.3 million in capital spending.

Since the 2007 rate case, we have completed numerous projects focusing on the improved reliability of the Company's Fossil-Hydro fleet. Turbine and generator ("T/G") equipment reliability has been a major focus area, and $71.3 million has been spent on projects such as generator stator and rotor rewinds, turbine steampath upgrades, turbine valve replacements, turbine rotor replacements and other supporting T/G equipment. The coal fleet boilers continue to be a major focus of reliability programs as well; $72.7 million has been spent on boiler tube replacements and supporting boiler equipment projects to minimized forced outage events. This focus on unit availability and reliability also extends out to the remaining balance of plant equipment where an additional $78.8 million has been spent on projects related to valves, coal mills, coal handling equipment, controls, electrical equipment, motors and other equipment. In light of severe drought and low stream flow conditions experienced in Duke Energy Carolinas' service territory during 2007 and 2008, the Company spent $21.2 million implementing capital projects to increase its ability to operate its generation units at reduced reservoir levels and stream flows.

In addition to these projects I have described, Duke Energy Carolinas has invested $56.7 million on projects required for hydro relicensing and other smaller programs related to its existing fossil-hydro fleet.

Q. IN YOUR OPINION ARE THESE POST-2007 GENERATION ADDITIONS USED AND USEFUL IN PROVIDING SERVICE TO DUKE ENERGY CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes, they are. The environmental projects are necessary for compliance with local, State and Federal environmental regulations. The $502.8 million cost of the Allen scrubbers is in addition to the $1.05 billion Duke Energy Carolinas has invested in environmental controls equipment placed in service and amortized through year end 2008 in order to comply with the Clean Smokestack Act. In addition, the Allen scrubbers are necessary for compliance with Phase 1 of the Federal Clean Air Interstate Rule ("CAIR"), which begins in 2010 for SO_2 unless and until the Environmental Protection Agency ("EPA") promulgates a new rule.

The additional capital investments I discussed above have enabled the Company to continue to provide reliable generation service to our customers at reasonable costs.

Q. WHAT NEW FOSSIL AND HYDRO GENERATION UNITS ARE PLANNED FOR THE DUKE ENERGY CAROLINAS SYSTEM?

A. The most significant investment in new generation is our addition of a new, nominally-rated 800MW state-of-the-art supercritical pulverized coal unit ("Unit 6") at the Company's Cliffside Steam Station in Cleveland County, North Carolina, in accordance with the Certificate of Public Convenience and Necessity ("CPCN") issued on March 21, 2007, in Docket No, E-7, Sub 790 ("Cliffside Project"). The Company is making good progress on the engineering, procurement and construction activities for this project. As noted in the Company's 2009 annual Cost Estimate Report (filed on February 27, 2009) as of December 31, 2008, the Cliffside Project was approximately 29% complete, and as of the end of the quarter ending March 31, 2009, it is approximately 35% complete. Although the nominal plant rating based upon worst conditions is 800 MW, additional engineering work completed subsequent to the Commission's issuance of the CPCN leads us to the conclusion that the average annual output of the new advanced clean Unit 6 will be closer to approximately 825 MW. The Company plans for Cliffside Unit 6 to be in service by the summer of 2012. As discussed in the testimony of Company Witness Shrum, Duke Energy Carolinas projects that as of September 30, 2009, it will have recorded $1 billion[1] in construction work in progress ("CWIP") associated with the Cliffside Project.

Notably, the construction of a new Unit 6 at Cliffside is part of a larger modernization effort at the site which also involves the addition of a scrubber on Unit 5 (work that is ongoing and is not included this rate increase request) and the retirement of existing Units 1 through 4 once Unit 6 comes on line.

As discussed by Company Witness De May in his testimony, approval of the Company's request for recovery of its financing costs related to construction of Cliffside Unit 6 through the inclusion of this CWIP in rate base will be received positively by credit rating agencies and the financial community, as it will improve the Company's cash flow position and reduce regulatory lag. Further, such recovery benefits customers because better credit quality translates to lower financing costs and better access to capital thereby reducing costs for customers over time, and phasing in rate increases associated with large capital investments helps protect consumers against a spike in rates that can occur when the full impact of these larger investments hits all at one time.

[1] On a total system basis, including AFUDC.

Given the Company's obligation to retire existing units and the expiration of purchased power resources, Duke Energy Carolinas must make investments over the next three to five years to ensure adequate resources to meet customer demand, even in light of the projected near-term reduction in load growth caused by the current economic conditions. Furthermore, even in this recessionary economy, people and businesses continue to move to the Carolinas, and the Company continues to expect long-term growth in demand. The economy will come back, and resource needs are expected to increase significantly over the next twenty years. The 2008 Duke Energy Carolinas Annual Plan has identified approximately 2,690 MW of additional resources that are needed by 2012. By 2028, that number grows to 8,800 MW.

These resource needs reflect the Company's commitment to retire 445 MW of older coal units by 2012 and an additional retirement of 600 MW of older coal units by 2018. Cliffside Unit 6 and the Buck and Dan River combined cycle units that are expected to be operational by the summer of 2012 will fulfill 2,065 MW of this need, and will contribute to our efforts to reduce the carbon intensity of our fleet. We continue to evaluate the timing of the Buck and Dan River Combined Cycle projects so as to be optimize our resources portfolio to meet short-term capacity needs and facilitate retirements of older, less efficient coal-fired units. Duke Energy Carolinas also plans for the following capacity additions in support of these resource requirements: the 31.5 MW replacement hydroelectric station at the Bridgewater site; 50 MW at its Jocassee Hydroelectric pumped storage facility related to the installation of new runners in 2011, and an estimated 36 MW capacity addition at its Belews Creek station due to increased efficiency from new low pressure turbine rotors.

Q. WHAT IS THE ANTICIPATED CAPITAL BUDGET FOR FOSSIL-HYDRO OPERATIONS OVER THE NEXT THREE-YEAR PERIOD?

A. The Company has delayed some capital spending in light of the credit crunch; however, in order to meet environmental compliance requirements and to continue to provide reliable service to customers, Duke Energy Carolinas plans to invest $1,018 billion in its Fossil-Hydro plant during the period 2009-2011.

III. <u>PERFORMANCE OF THE FOSSIL-HYDRO FLEET</u>

Q. HOW DOES THE FOSSIL-HYDRO OPERATIONS DEPARTMENT SEEK TO MEET THE OBJECTIVES YOU DISCUSSED ABOVE?

A. The Duke Energy Carolinas' Fossil-Hydro generation department seeks to safely provide reliable and cost effective electricity to our Carolinas' customers through our focus in a number of key areas. Operations personnel and other station employees are well trained and execute their responsibilities to the highest standards, in accordance with procedures, guidelines and a standard operating model. Like safety, environmental compliance is a "first principle," and we work very hard to achieve compliance with all applicable environmental regulations. We maintain station equipment and systems in a cost-effective manner to ensure the reliability and availability of our units. We take action in a timely manner to implement work plans and projects that enhance the performance of systems, equipment and personnel, consistent with providing low-cost power to our customers. Equipment inspection and maintenance outages are scheduled when appropriate, are well-planned and executed with quality, with the primary purpose of preparing the plant for reliable operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DUKE ENERGY CAROLINAS' FOSSIL GENERATING SYSTEM DURING THE TEST PERIOD.

A. Duke Energy Carolinas' fossil generating system operated efficiently and reliably during the test period. Two key measures are used to evaluate the operational performance of generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power if needed. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity.

Duke Energy Carolinas' seven base load coal units achieved results of 84.5% equivalent availability factor and 76.6% capacity factor over the test period. During the peak summer season within this test period, these base load units achieved excellent results of 91.7% equivalent availability factor and 83.1% capacity factor. The Company's thirteen intermediate coal units achieved results of 84.2% equivalent availability factor and 55.8% capacity factor over the test period, and performed similarly during the summer peak months at 86.0% equivalent availability and 62.3% capacity. Duke Energy Carolinas' ten peaking coal units achieved results of 88.7% equivalent availability factor and 32.7% capacity factor for the test period, and performed similarly during the summer peak months at 84.7% equivalent availability and 36.2% capacity.

The Company's combustion turbines were available for use as needed in this time period, with a 95.9% starting reliability result for the large combustion turbines at the Lincoln, Mill Creek and Rockingham plants.

These results are indicative of solid performance and good operation and management of Duke Energy Carolinas' fossil fleet during the test period.

Q. DURING THE TEST PERIOD, HOW DID THE COMPANY'S COAL UNITS PERFORM AS COMPARED TO THE INDUSTRY?

A. Duke Energy Carolinas has long been an industry leader in achieving low heat rates, which indicates an efficient generating system that uses less heat energy from fuel to generate electrical energy. Duke Energy Carolinas' Belews Creek Steam Station and Marshall Steam Station consistently rank among the most efficient coal plants in the nation. As an example, in the January/February 2009 issue of *Electric Light and Power* magazine, Duke Energy Carolinas' Belews Creek Steam Station and Marshall Steam Station ranked as the country's third and sixth most energy efficient coal-fired generators, respectively.

The system coal units achieved a fleet-wide equivalent availability factor of 84.7% for the test period and 89.5% during the summer peak months. These results are comparable with the most recently published NERC average equivalent availability for all North American coal plants of 84.8%. This NERC availability average covers the period 2003-2007 and represents the performance of over 800 North American coal-fired units.

Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S HYDROELECTRIC FACILITIES DURING THE TEST PERIOD.

A. The hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 89.2% and with an excellent low forced outage factor of 0.9%. Absent the impact of drought-related restrictions, this system availability factor was 92.8% with a forced outage factor of 0.8%.

IV. FOSSIL-HYDRO COST AND CHALLENGES

Q. WHAT ARE THE SIGNIFICANT COST DRIVERS IMPACTING OPERATION AND MAINTENANCE EXPENSES FOR THE FOSSIL-HYDRO FLEET?

A. Operations and maintenance ("O&M") expenditures for the Company's fossil and hydro facilities are made up of both fuel and non-fuel items. For the fossil units, approximately 85% of these required O&M expenditures are fuel-related (primarily coal, but also natural gas, fuel oil, environmental reagents and net proceeds from sale of by-products). A complete discussion of fossil fuel and fuel-related costs in the test period is included in the testimony of Vincent E. Stroud and John J. Roebel filed with the Commission in Docket No. E-7, Sub 875. Non-fuel items comprise the remainder of these O&M expenditures for the fossil and hydro facilities. The majority of these non-fuel expenditures are for labor costs from Company or contract resources to operate, maintain or support the facilities.

Duke Energy Carolinas will incur additional non-fuel O&M costs over the next three years in order to operate and maintain the environmental control equipment and new generation resources I discussed above. Over the last several years we have seen rapid and substantial increases in labor, material and contract services required for the operation and maintenance of these new and existing facilities. The recent economic downturn has moderated these increases; however, we will continue to be challenged by high costs for these products and services driven by market demand, limited availability of commodities and skilled technical and craft resources, in addition to inflationary pressures. The Company will continue to review these costs and their drivers, and pursue initiatives that optimize the use of funds for the greatest benefit to overall cost and reliability.

Q. WHAT STEPS HAVE FOSSIL-HYDRO OPERATIONS TAKEN TO CONTROL COSTS AND MITIGATE THE IMPACT OF THE INCREASES YOU DISCUSSED?

A. Duke Energy Carolinas maintains a continuous focus on improving operational results and cost effectiveness in operation of its fossil and hydroelectric fleet. For example, the Fossil-Hydro Generation Excellence Program provides each station with a structured process for identifying and evaluating cost savings or process improvement ideas, initiating projects to implement these improvement ideas, measuring results and sharing of ideas with other stations for implementation as applicable. These efforts support the overall goals of the program to establish a culture of proactively striving for continuous improvement throughout the generation fleet and to work collectively to achieve higher standards through continuous and lasting improvement.

In addition to these continuous improvement and cost reduction efforts, by virtue of operating a larger fleet the Fossil-Hydro organization has the opportunity to expand its understanding and sharing of best practice and process improvement ideas. Further, sharing of technical resources and other support functions results in overall cost savings for the organization. The following examples demonstrate how aligning our organization to serve customers of each of our operating companies has improved operations and cost effectiveness:

- Sourcing teams evaluate combined needs for significant purchases of materials and services, creating savings opportunities due to buying power/leverage, streamlined procurement, etc.
- Process improvement initiatives are integrated, allowing for a broader application of effective cost savings ideas and best practices.
- Technical expertise is leveraged over a larger fleet, allowing for a more cost effective engineering/technical support structure.
- Environmental health and safety practices can be consistently applied across a larger fleet, ensuring best practices are employed in these critical areas.

These improvement initiatives result in a higher-performing and leaner organization, a culture of continuous improvement, and a more cost effective operating structure. However, despite these efforts the Company continues to face the impacts of new costs and inflationary pressures that are not offset by new revenues due to flattening load growth.

Q. WHAT CHALLENGES DOES DUKE ENERGY CAROLINAS FACE AS TO ITS FOSSIL-HYDRO OPERATIONS?

A. With the significant additions of environmental control equipment that have been required by federal, state or local regulatory mandates, one of the biggest challenges for the fossil-hydro fleet will be to effectively incorporate the operation and maintenance of this equipment into the overall management of the fleet. As these equipment additions are placed in service we must diligently expand and execute continuous improvements efforts related to the availability and reliability of the fleet, and cost control. As discussed by Witness Trent, we anticipate additional environmental legislation and regulations will be enacted which will intensify these challenges. Our focus on generation excellence, process improvement and cost control will also be critical as older generating units are retired and new generating units are placed in service.

V. DUKE ENERGY CAROLINAS' ELECTRIC TRANSMISSION AND DISTRIBUTION SYSTEM FACILITIES

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY CAROLINAS' ELECTRIC DELIVERY SYSTEM SERVING NORTH CAROLINA.

A. Duke Energy Carolinas' electric delivery system provides retail service to approximately 2.4 million customers located throughout our service area in the central and western part of North Carolina and western South Carolina. Duke Energy Carolinas also sells electricity at wholesale to municipal, cooperative, and investor-owned utilities.

Duke Energy Carolinas' electric delivery system includes approximately 13,000 circuit miles of transmission lines and 100,400 miles of distribution lines. The delivery system also includes 1,596 distribution and industrial substations, and 175 transmission substations. Duke Energy Carolinas' North Carolina electric system is operated as a single control area with the South Carolina electric system, and is directly interconnected with eight other utilities. Duke Energy Carolinas' electric delivery system includes various other equipment and facilities such as control rooms, computers, capacitors, street lights, meters, protective relay equipment and telecommunications equipment and facilities.

VI. DUKE ENERGY CAROLINAS' INVESTMENT IN ITS TRANSMISSION AND DISTRIBUTION FACILITIES

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY CAROLINAS' NORTH CAROLINA ELECTRIC DELIVERY SYSTEM HAS GROWN SINCE THE COMPANY'S LAST GENERAL RATE CASE IN 2007.

A. Duke Energy Carolinas is focused on delivering safe reliable service and minimizing outages through effective asset management. To that end, as of December 31, 2008, we have invested $1.154 billion in our Carolinas electric delivery system between 2006 and 2008, constituting a 12.3% increase. The Company made these investments to add capacity to meet the demands of new and existing customers as well as to improve the reliability and integrity of the system.

From January 1, 2007 through December 31, 2008, Duke Energy Carolinas added 26 new substations; added 3,159 miles of distribution lines; added or upgraded 50 circuit miles of transmission lines; installed 62,454 poles and added new service at 116,054 locations in our service territory.

Q. HAS DUKE ENERGY CAROLINAS INCURRED COSTS TO IMPROVE ITS POWER DELIVERY SYSTEM THAT ARE NOT ASSOCIATED WITH THE ADDITION OF NEW CUSTOMERS?

A. Yes. To continue the high degree of reliability our customers need and expect, we have invested in reliability programs to prevent outages, minimize interruptions and extend the life of our equipment. We selected and developed programs that maximize the reliability improvement achievable for the investment. Our sectionalization projects optimize the placement of protective devices on all distribution circuits resulting in the least number of customers interrupted when outages occur. The transformer retrofit program addresses the root cause of outages directly, preventing animal and lightning outages, and extending the life of line transformers. The pole inspection, treatment, and replacement program extends the life of poles, and prevents outages and damage caused by the natural deterioration and failure of poles. The replacement of analog distribution breaker relays with microprocessor relays has reduced the number of momentary customer interruptions, and provided information that has reduced sustained customer interruptions and breaker malfunctions as well. The declared circuit program identifies distribution circuits for which additional reliability spending will significantly reduced the number of customer interruptions.

From January 1, 2009 through September 30, 2009, Duke Energy Carolinas expects to invest an additional $170.9 million in reliability and capacity projects to address the demands of existing customers. These investments are necessary to maintain the reliability and integrity of the system as equipment ages and growth in specific geographic areas necessitates changes in system configuration. As our customers' power quality requirements grow more rigorous, Duke Energy Carolinas must continually refine its reliability strategies to meet customer's expectations.

Because these investments are not associated with provision of service to new customers, they do not produce incremental revenue. Over the near term, we expect such costs to continue at the current level or increase.

Q. IN YOUR OPINION, ARE DUKE ENERGY CAROLINAS' NORTH CAROLINA ELECTRIC DELIVERY SYSTEM FACILITIES USED AND USEFUL IN PROVIDING SERVICE TO DUKE ENERGY CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. In my opinion, they are. They are used daily to provide safe, reliable, efficient and economical electric delivery service to our North Carolina customers.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' PROJECTED INVESTMENT RELATING TO ITS TRANSMISSION AND DISTRIBUTION FACILITIES.

A. As I discussed in connection with the fossil-hydro fleet, in light of the current economic conditions, Duke Energy Carolinas has deferred capital expenditures for its transmission and distribution facilities where possible. In order to continue to provide reliable service, however, these expenditures are projected to increase, as shown by the following table:

Table 1 – Capital Expenditures 2007 - 2011 ($ millions)

	2007	2008	Forecasted 2009	Forecasted 2010	Forecasted 2011
Transmission	112.7	113.0	114.1	143.7	161.3
Distribution	474.7	453.8	369.4	538.0	603.8
Total	587.4	566.8	483.5	681.7	765.1

VII. OPERATING AND MAINTAINING THE RELIABILITY OF DUKE ENERGY CAROLINAS' ELECTRIC DELIVERY SYSTEM

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY CAROLINAS' TRANSMISSION AND DISTRIBUTION SYSTEM IS OPERATED AND MAINTAINED.

A. Duke Energy Carolinas designs, constructs, operates and maintains its transmission and distribution system in accordance with good utility practice by following numerous inspections, monitoring, testing, and periodic maintenance programs. Examples of these programs include the following programs: substation inspection and maintenance, transmission tower inspection, pole inspection, vegetation management, outage follow up, underground cable and equipment replacement, capacitor installation and maintenance and substation transformer gas analysis. These programs are designed and implemented to balance the reliability, safety and affordability goals I discuss above. Duke Energy Carolinas uses various methods to measure the effectiveness of its maintenance programs and resulting system reliability. As I discuss further below, the Company also uses customer feedback in order to develop and implement programs that best meet customer needs and expectations.

Q. PLEASE EXPLAIN THE METHODS DUKE ENERGY CAROLINAS USES TO MEASURE THE EFFECTIVENESS OF ITS MAINTENANCE PROGRAMS AND SYSTEM RELIABILITY.

A. Duke Energy Carolinas uses several measures to determine overall success of reliability programs. The measures include customer satisfaction ratings as well as industry accepted reliability indices. Direct interviews with residential and non-residential customers indicate a clear preference for eliminating outages altogether versus focusing on reducing outage duration. As such, reliability programs are designed to eliminate outages.

Company Witness Carter describes the three key customer service measures used to evaluate power delivery maintenance programs and reliability: (1) the J.D. Power and Associates ("J.D. Power") Residential customer survey; (2) the J.D. Power Business customer survey; and (3) the Key Accounts National Benchmark survey measuring residential, small business and large customer satisfaction scores, respectively. As discussed by Mr. Carter, Duke Energy Carolinas consistently outperformed the scores of the industry average and the Southern regional average.

Three industry accepted reliability indices as defined by IEEE Standard 1366-2003 are:

System Average Interruption Frequency Index ("SAIFI") represents the average number of interruptions greater than five minutes per customer during the course of a year. SAIFI is expressed by the total number of interruptions divided by the total number of customers served.

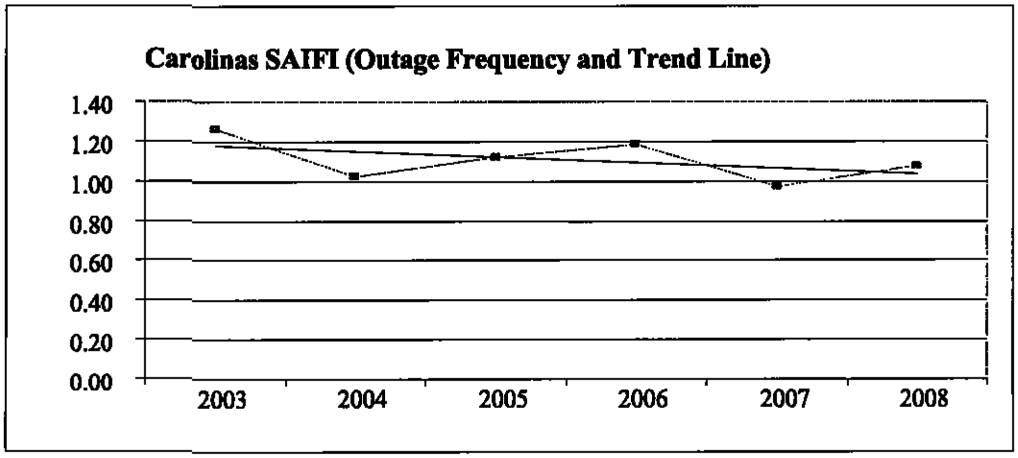
Momentary Average Interruption Frequency Index ("MAIFI") is the average momentary (less than five minutes) interruption experienced per customer during one year, and is expressed by the total number of momentary interruptions divided by the total number of customers served.

System Average Interruption Duration Index ("SAIDI") is the average number of minutes each customer is interrupted per year, and is expressed by the sum of customer interruption durations (in minutes) divided by the total number of customers served.

Q. HOW HAS DUKE ENERGY CAROLINAS' SYSTEM PERFORMED AS MEASURED BY THESE INDUSTRY INDICES?

A. Duke Energy Carolinas' reliability scores reflect the balanced and planned programmatic strategy deployed by the operating team. The Company's SAIFI reliability index results indicate a trend of steady improvement over the last several years as shown in the graph below:

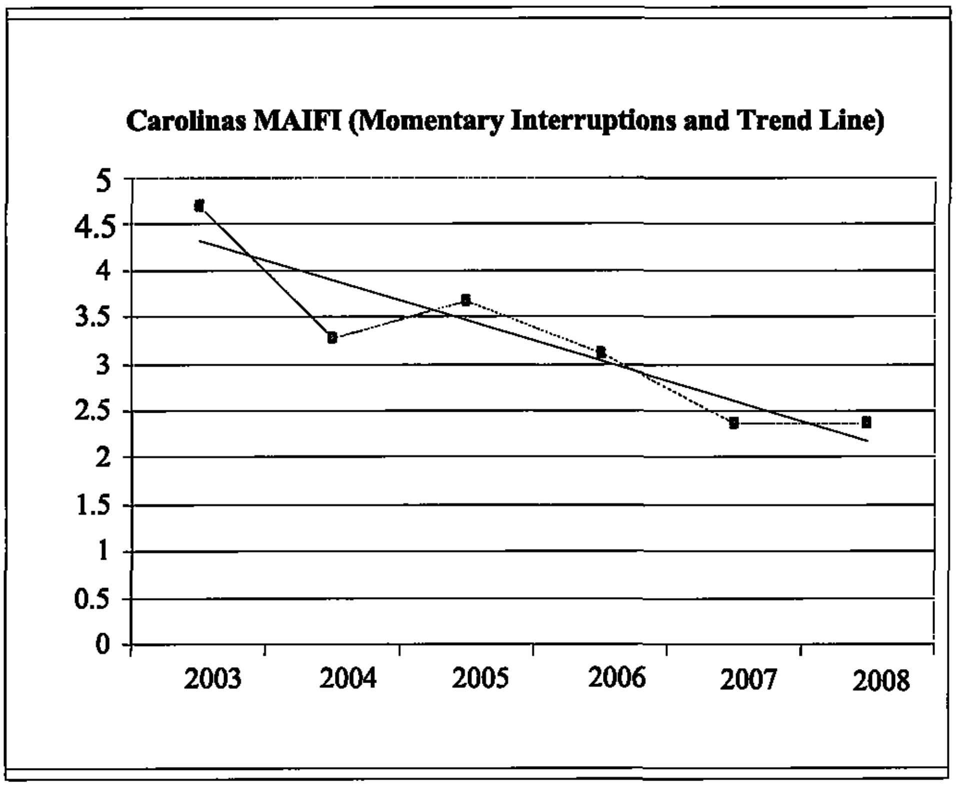
Figure 1 – Carolina SAIFI Performance



As I noted above, our research indicates that SAIFI is one of the most significant contributors to customer satisfaction with respect to the reliability of service. Therefore, Duke Energy Carolinas continually tracks the highest contributors to SAIFI and develops proactive programs to address known and emerging trends.

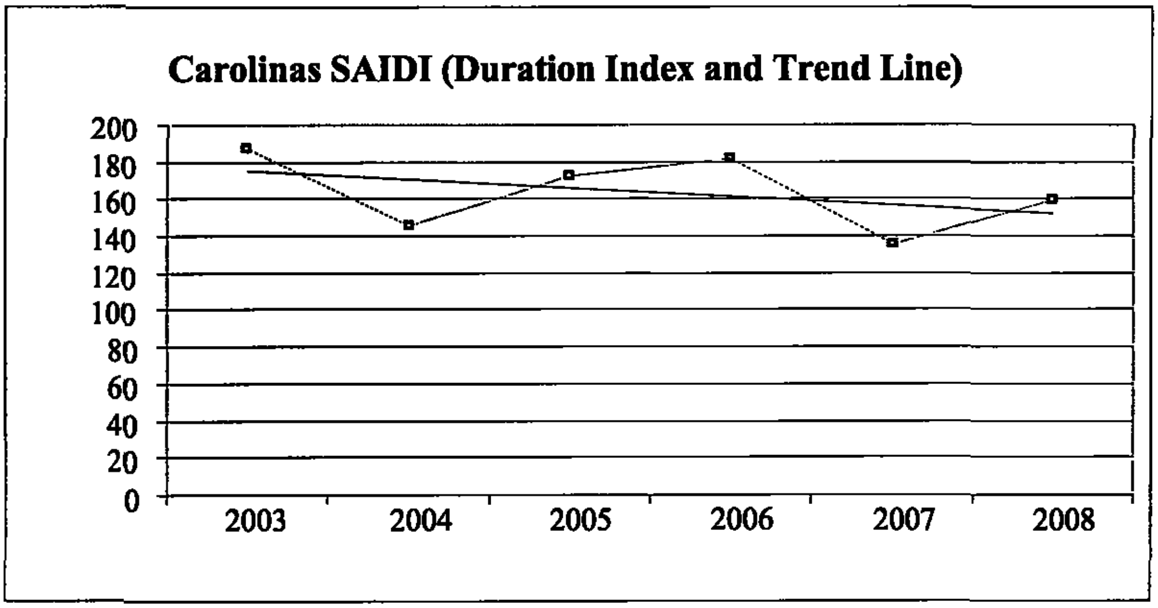
Momentary interruptions have also significantly decreased in recent years due to the reliability programs I discussed above and are displayed in the following graph.

Figure 2 – MAIFI Performance



Outage duration has continued to remain reasonably consistent over the past several years. Customers continue to reinforce the need to eliminate outages, not reduce duration and as such our programs do not primarily focus on duration. Nonetheless, Duke Energy remains committed to the timely and safe restoration of power when outages do occur.

Figure 3 – Carolinas SAIDI



Q. HOW HAS DUKE ENERGY CAROLINAS CONTROLLED OPERATIONS AND MAINTENANCE EXPENSES FOR ITS TRANSMISSION AND DISTRIBUTION SYSTEM?

A. Cost control requires consistent and steady management. Process re-engineering, information technology system implementation, mobile meter reading and the efficiencies from operating a shared service model have enabled the Company to manage its operation and maintenance ("O&M") costs in light of inflationary pressures and new costs since the last general rate increase in 1991.

Duke Energy Carolinas and its utility operating companies in the Midwest have dedicated geographic-based teams focusing on basic engineering, construction and service delivery. Although these geographical-based teams are the largest transmission and distribution operational teams, our shared utility support organization has allowed us to supplement these teams with smaller technical and operational support teams to serve both Carolinas and Midwest needs. These smaller technical and operational support teams charge only based on services rendered, enabling each geographic area access to services on demand, based on need. This shared support model has proven very efficient and effective for securing operational efficiencies, developing best practices, and controlling the costs of transmission and distribution operations.

Sharing best practices also helps us identify and implement significant opportunities for improvement. A number of best practices have been identified and implemented in both the Carolinas and Midwest. For example, the most significant best practices implemented in the Carolinas include:

- Integration of reliability-based programs leading to improved practices in the Carolinas for managing damage assessments during storms.
- Implementation of centralized distribution work centers managing deployment of work orders 24/7, moving the Carolinas away from dispersed dispatching, and toward a more efficient and more effective centralized approach.
- Combining major storm organizations to provide significant additional labor, material and equipment support during major storms.
- Leveraging major materials and labor contracts to take advantage of increased scale, resulting in partial mitigation of inflationary increases, particularly in the materials area.

a "Smart Grid" – are necessary to enable the next generation of energy efficiency programs, distributed generation and renewable integration, as well as distribution automation-related reliability improvements and improved system functionality.

In addition to meeting customers' expectations, we must ensure that our transmission and distribution system is sufficiently robust to facilitate power deliveries from off-system energy purchases and to support renewable and distributed generation. Many of our existing systems are beginning to reach their maximum potential and new systems must replace them to ensure the level of reliability our retail customers have come to expect. The implementation of North Carolinas' renewable energy and energy efficiency portfolio standard, as well as the potential for a federal renewable portfolio standard will place new demands and stresses on the power delivery system as intermittent renewable generation and distributed generation on the system increases. Meeting these needs means significant investment in strategic new transmission corridors and generation connections.

Q. WHAT STEPS IS DUKE ENERGY CAROLINAS TAKING TO INVESTIGATE SMART GRID TECHNOLOGY TO ADDRESS THESE CHALLENGES?

A. Since 2006, Duke Energy Carolinas has been investigating Smart Grid compatible equipment such as new substation circuit breakers, electronic reclosures in high customer density areas, relay replacements, new capacitor banks, and backhaul communications to substations. More recently, Duke Energy Carolinas began piloting Smart Grid equipment to identify solutions to the reliability challenges we face as well as to provide greater information and opportunities to customers to use energy more efficiently. As discussed by Company Witness Trent, initial Smart Grid deployments are underway in both North Carolina and South Carolina, with over 11,000 smart meters currently deployed. The North Carolina site is located in South Charlotte and incorporates distribution automation equipment at the McAlpine substation. The South Carolina site is located in the Upstate area and is designed to test the communications architecture in a rural environment. These demonstration projects are evaluating the ability of Smart Grid technology to (1) improve system reliability by reducing outages and outage duration; (2) improve power quality through voltage optimization; (3) enhance operational efficiencies through distribution automation; (4) improve system performance through more detailed and more timely data collection; and (5) decrease power consumption by controlling voltage more efficiently.

The South Charlotte demonstration site will also host the Residential Energy Management System ("EMS") Pilot recently approved by the Commission in Docket No. E-7, Sub 906. The EMS pilot will test an in-home gateway device that provides access to an online energy management website in order for the participants to remotely monitor and control their energy use. Participants may also allow the Company to manage their energy use based on a personal energy profile. This pilot will provide Duke Energy Carolinas with information on the technical potential, customer preferences, and operational characteristics of such systems as enabled by smart grid technology. Furthermore, the EMS pilot will assess the use of such equipment to increase the overall efficiency of the grid by leveling peak distribution demands and deferring the need for additional circuit capacity.

The Company will use the results of these pilots to develop a cost-effective smart grid utilization and deployment strategy for the Carolinas. Duke Energy Carolinas is also evaluating opportunities to apply for federal stimulus funds under the American Reinvestment and Recovery Act of 2009 to offset smart grid demonstration and deployment costs.

Q. PLEASE EXPLAIN THE FEDERAL RELIABILITY AND CRITICAL INFRASTRUCTURE PROTECTION ("CIP") STANDARDS.

A. On August 8, 2005, the Electricity Modernization Act of 2005, which is Title XII, Subtitle A of the Energy Policy Act of 2005 ("EPAct 2005'), was signed into law. EPAct 2005 added a new section 215 to the Federal Power Act. Section 215 assigns to the Federal Energy Regulatory Commission ("FERC") the responsibility and authority for overseeing the reliability of the bulk power systems in the United States, including establishing and enforcing mandatory reliability standards. The FERC certified the North American Electric Reliability Corporation ("NERC") as an industry, self-regulating Electric Reliability Organization, as envisioned in the legislation. NERC proposed and FERC thereafter established mandatory reliability standards for bulk transmission systems on March 16, 2007, in Docket No. RM06-16-000. In its final rule, the Commission approved 83 reliability standards which became mandatory and enforceable on June 18, 2007. In a subsequent series of orders, FERC revised or approved approximately 22 reliability standards. These standards cover a wide range of topics including Vegetation Management, Cyber

Security, Protections and Control, Transmission Planning, Emergency Preparedness and Operations. In January 2008, the FERC approved eight cyber security standards which require certain users, owners, and operators of the bulk power system to comply with requirements to safeguard critical cyber assets. Currently, NERC has an ongoing project to develop additional standards and modify others pursuant to FERC instructions.

Q. HOW DO THESE MANDATORY RELIABILITY AND CIP STANDARDS DIFFER FROM THE VOLUNTARY STANDARDS THAT THE COMPANY OPERATED UNDER PRIOR TO JUNE, 2007?

A. At the outset, it is important to note that Duke Energy has fully supported the adoption of mandatory reliability standards. While the Duke Energy Carolinas system has an outstanding reliability record, practices and processes are always subject to enhancement, and Duke Energy's philosophy is one of "continuous improvement." Broadly, the mandatory reliability standards make compliance equally applicable to all transmission industry participants, and, in most cases, make clear what constitutes compliance. These standards will result in industry participants investing more resources in the bulk electric system.

The key differences from the previous voluntary standards are in the detail of the standards. The mandatory standards are often far more detailed and go into more depth than the old voluntary standards. In addition, the mandatory standards cover additional operational aspects of the electric delivery system that were not covered in the past, such as certain aspects of vegetation management and cyber security. Many of the mandatory standards require the Company to develop extensive documentation processes, which occupy significant employee time, and have no direct impact on reliability. Similarly, participation in the lengthy processes through which the standards are developed by NERC and submitted to FERC continues to require employee attention and involvement, including serving on various standards drafting committees and forums. The Company estimates that in 2008 over 30 full time equivalents were devoted to participating in Duke Energy's Reliability Standards Compliance Administration Program ("CAP") documentation and administrative compliance efforts. In order to comply with the Reliability Standards, we spent approximately $2.9 million on administrative compliance activities and related reliability projects over and above planned expenditures for 2008.

But more importantly, it is the manner in which the standards are sometimes interpreted and applied that is of greater concern to the Company. Unlike the regional reliability organizations (such as SERC Reliability Corporation ("SERC")), which took a technical approach to evaluating the standards and their application, FERC appears to have rejected a "lessons learned" approach. Rather, FERC looks to be headed in the direction of taking a strict liability approach to enforcement, such that if an event warrants self-reporting to a regional reliability organization, assessment of a violation and penalties is highly likely to follow, regardless of the impact on the bulk transmission system and regardless of the company's coming forward voluntarily to self-report. It is not yet clear whether proposed penalties will be reasonably proportional to the accompanying alleged violations and whether appropriate credit will be given for mitigating factors actions and robust compliance programs. Duke Energy Carolinas believes that such enforcement policies can, in some cases, be punitive to the industry and a distraction from the laudable goal of enhancing system reliability. We will continue to work with FERC, NERC, and SERC to help create a reliability compliance framework that emphasizes continuous improvement over penalties.

Q. WHAT IMPACT COULD THE INTERPRETATION AND APPLICATION OF THE MANDATORY RELIABILITY STANDARDS HAVE ON POWER DELIVERY OPERATIONS?

A. As I have discussed above, Duke Energy Carolinas seeks to appropriately balance reliability, affordability, and environmental stewardship in its operation of its system. We are concerned that if the mandatory reliability standards are, in some cases, interpreted such that any reportable event, even where there is no impact on customers, generators or the bulk transmission system, is deemed to be a violation resulting in penalties, that we will be required to spend substantial additional funds for equipment and processes which bring little incremental improvement in reliability. If the FERC enforcement policy develops such that there is an absence of a meaningful cost-benefit analysis aspect to enforcement decisions, the potential exists for increased costs to consumers without a corresponding benefit to reliability. We are hopeful that as the entire industry gains more experience with reliability enforcement, those tasked with ensuring reliability compliance will balance the understandable concern about enforcement with a recognition of the Company's fundamental operational goal of providing safe, reliable service at reasonable cost.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT DUKE ENERGY CAROLINAS' OPERATIONS, INVESTMENTS, AND COST MANAGEMENT.

A. In summary, Duke Energy Carolinas continues to safely operate its business in a manner that appropriately balances affordability, reliability and environmental stewardship. Since 2006, we have invested over $2 billion in our fossil-hydro fleet and power delivery system for additions and capital improvements necessary to safely provide reliable electric service to our customers in full compliance with environmental and other regulatory requirements. Our operational track record demonstrates that we have been successful in the balance we have struck and continue to strike on these key attributes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	DHIAA M. JAMIL
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A. My name is Dhiaa M. Jamil. My business address is 526 South Church Street, Charlotte, North Carolina. I am Group Executive and Chief Nuclear Officer for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY CAROLINAS?

A. As Group Executive and Chief Nuclear Officer, I am responsible for the safe, reliable and efficient operation of the Company's three nuclear generating stations – Catawba, McGuire and Oconee nuclear stations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in electrical engineering. I am a professional engineer in North Carolina and South Carolina and have completed the Institute of Nuclear Power Operations' ("INPO") senior nuclear plant management course and received my Duke Energy technical nuclear certification. I served as a senior member of the Institute of Electrical & Electronics Engineers ("IEEE") and recently completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. I was also a member of Dominion Energy Management Safety Review Advisory Committee, the Tennessee Valley Authority Nuclear Safety Review Board, and currently serve on the INPO Executive Advisory Group and the Charlotte Research Institute board of directors.

I am currently the chairman of the Energy Production and Infrastructure Center ("EPIC") Advisory Board for the University of North Carolina at Charlotte. I began my career at Duke Energy Carolinas in 1981 as a design engineer in the design engineering department. After a series of promotions, I was named Oconee Nuclear Station Electrical Systems Engineering Supervisor in 1989; Electrical Engineering Manager in 1994; Maintenance Superintendent, McGuire Nuclear Station, in 1997; Station Manager of McGuire in September 1999; and Vice President of McGuire Nuclear Site in September 2002. I was named Vice President of Catawba Nuclear Station in July 2003, with responsibility for all aspects of the safe and efficient operation of the nuclear site. In December 2006, I was named Senior Vice President of Nuclear Support, where I was responsible for plant support, major projects and fuel management for the nuclear fleet. I was also responsible for regulatory support, nuclear oversight and safety analysis functions. I was named to my current role as Group Executive and Chief Nuclear Officer in January 2008.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss 1) the purchase of a portion of Saluda River Electric Cooperative, Inc.'s interest in the Catawba Nuclear Station and other capital additions since the 2007 rate case, 2) the operational performance of Duke Energy Carolinas' nuclear generation fleet during the January 2008 through December 2008 test period and 3) key drivers impacting O&M costs for nuclear operations.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' NUCLEAR GENERATION PORTFOLIO.

A. Duke Energy Carolinas' nuclear generation portfolio consists of approximately 5200 megawatts ("MW") of generating capacity, made up as follows:

Oconee Nuclear Station - 2,538 MWs

McGuire Nuclear Station - 2,200 MWs

Catawba Nuclear Station - 435 MWs (Duke Energy Carolinas' 19.2% ownership of the Catawba Nuclear Plant)

Q. MR. JAMIL, PLEASE PROVIDE A GENERAL DESCRIPTION OF DUKE ENERGY CAROLINAS' NUCLEAR GENERATION ASSETS.

A. Duke Energy Carolinas' nuclear fleet consists of three generating stations. Oconee Nuclear Station, located in Oconee County, South Carolina, began commercial operation in 1973 and was the first nuclear station designed, built and operated by Duke Energy Carolinas. It has the distinction of being the second nuclear station in the country to have its license renewed, originally issued for 40 years, by the U.S. Nuclear Regulatory Commission ("NRC") for an additional 20 years.

McGuire Nuclear Station, located in Mecklenburg County, North Carolina, began commercial operation in 1981. Duke Energy Carolinas jointly owns the Catawba Nuclear Station, located on Lake Wylie in York County, South Carolina, with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation ("NCEMC"), and Piedmont Municipal Power Agency. Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for an additional 20 years each. On September 30, 2008, the Company and NCEMC closed on the previously agreed upon purchase of Saluda River's ownership interest in Unit 1 of Catawba Nuclear Station.

Following the close of the purchase, Duke Energy Carolinas' ownership interest in the Catawba station increased from 12.5% to 19.2%.

II. INCREASED OWNERSHIP INTEREST IN CATAWBA AND OTHER CAPITAL PROJECTS

Q. PLEASE DESCRIBE THE TRANSACTION THAT LED TO DUKE ENERGY CAROLINAS INCREASED OWNERSHIP INTEREST IN THE CATAWBA NUCLEAR STATION.

A. On September 30, 2008, Duke Energy Carolinas completed the previously agreed to purchase of a portion of Saluda River Electric Cooperative, Inc.'s ("Saluda River") approximately seven percent ownership interest in the Catawba Nuclear Station. Under the terms of the agreement, Duke Energy Carolinas paid approximately $150 million for the additional ownership interest in Catawba. The assets purchased included decommissioning funds of approximately $41.5 million that Saluda River had accumulated for its share of decommissioning the plant. The funds were transferred to the external trustee responsible for managing Duke Energy Carolinas' decommissioning fund. Following the closing of the transaction, the Company owns approximately 19.2 percent of the Catawba Nuclear Station.

Q. HOW DID THE COMPANY DETERMINE THAT THIS WAS THE BEST *RESOURCE OPTION FOR ITS CUSTOMERS?*

A. As reflected in the Joint Application of Duke Energy Carolinas, LLC; N.C. Electric Membership Corporation; and Saluda River Electric Cooperative, Inc. to Amend the Certificate of Environmental Compatibility and Public Convenience and Necessity for Catawba Nuclear Station filed in Docket No. 2008-177-E before the Public Service Commission of South Carolina, Duke Energy Carolinas evaluated the purchase of 71.96 percent of the Saluda River interest in Catawba Nuclear Station as part of its 2006 and 2007 Integrated Resource Planning ("IRP") process and determined that the addition of Saluda River's share of Catawba Nuclear Station was a least-cost addition to the Company's generation portfolio and would benefit its customers. I understand that Duke Energy Carolinas' 2006 IRP approved by the Commission in Docket No. E-100, Sub 109 showed a need for the capacity in the timeframe of the acquisition, and the purchase of Saluda River's interest in Catawba and the gas-fired generation were the only viable options available. To determine the maximum price the Company should pay for Saluda River's interest in Catawba the Company performed a life-cycle analysis comparing it to an equal amount of capacity from a combined-cycle gas-fired generation plant. The purchase price for Saluda River's interest in Catawba did not exceed the maximum price determined in the life-cycle analysis.

Q. WHAT MAJOR CAPITAL PROJECTS HAS THE COMPANY UNDERTAKEN RELATIVE TO ITS NUCLEAR FLEET SINCE THE 2007 RATE CASE?

A. In 2007 and 2008, Duke Energy Carolinas closed nuclear capital projects that cost more than $330 million to improve the performance of its nuclear facilities and to address refurbishments necessary in order to ensure reliable extended life operations due to the license renewals granted by the NRC for Oconee, McGuire and Catawba. In addition, work necessary to comply with a NRC regulatory requirement to modify the containment sump was completed at McGuire and Catawba that I discussed in my testimony in Docket No. E-7, Sub 847. Other regulatory driven efforts included Alloy 600 mitigation efforts and groundwater monitoring. Significant investment has also been made to mitigate service water system piping degradation at Catawba due to raw water corrosion and biological effects on the carbon steel piping.

Q. IN YOUR OPINION ARE THESE NEW NUCLEAR GENERATION ADDITIONS USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DUKE ENERGY CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes they are. The acquisition of a larger percentage ownership of Catawba provides the Company with additional baseload capacity from a low cost generation asset that has been successfully operating for over 20 years. As I discussed above, the Company determined this acquisition was the least cost resource to meet increases in customer demand. Additionally, customers are already benefiting from reduced fuel costs associated with additional nuclear capacity. As a result of the Company's successful efforts to renew the licenses of its nuclear fleet, each for an additional 20 years, customers will continue to benefit from the generation provided by this reliable, cost-effective, and greenhouse gas emission-free base load source of electricity into the early-2040s. Our investments in refurbishment and enhanced performance of our existing nuclear fleet allow for the continued reliable and efficient operation of these assets that is reflected in the nuclear capacity factors I discuss below.

Q. WHAT TYPES OF PROJECTS ARE IN THE CAPITAL BUDGET FOR NUCLEAR OPERATIONS FOR THE NEXT THREE YEARS?

A. Over the next three years, the Company's plans include approximately $1 billion in capital spending. This budget includes similar types of projects to those in 2007 and 2008; however, projects related to regulatory commitments to the NRC for the continued operation of the Oconee Nuclear Station are driving the budget higher than in prior years. For the next several years, we will continue to pursue numerous projects necessary to support the extended life of our existing units, increase their reliability and upgrade technology. We are also performing a study to evaluate the potential to develop additional nuclear capacity through increasing the maximum power level at which our existing facilities may operate, called a power uprate. Major capital projects for the next three years include work related to the goal of continued safe, reliable operations, refurbishment of aging equipment, replacement or upgrades of obsolete equipment and upgrades and additions to plant systems based on changing regulations and standards. We plan for replacement of aged piping and components, based on systematic monitoring that has been performed.

Some additional examples include upgrading obsolete and aging analog controls systems to more reliable and accurate digital controls systems, and upgrades and enhancements to plant systems to meet changing regulatory requirements related to security, emergency response and materials upgrades. We are planning upgrades to plant structures and systems to address regulatory guidance concerning nuclear safety associated with natural events such as tornados. Additionally, the Company plans for capital expenditures associated with development work to preserve the option to build the Lee Nuclear Station. A description of such development work can be found in my direct filed testimony before this Commission in Docket No. E-7, Sub 819.

In addition to the projects included in the capital budget, the Company is also (1) reengineering certain of the Oconee projects necessary to meet NRC commitments that I noted above and (2) considering the appropriate timeframe in which to implement uprates if the study results are positive. These considerations may necessitate capital investment over and above the current capital budget.

III. NUCLEAR GENERATION TEST YEAR PERFORMANCE

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of Duke Energy Carolinas' nuclear generation department is to provide safe, reliable and cost effective electricity to the Company's Carolinas customers. The Company achieves this objective through its focus in a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards, in accordance with detailed procedures. The Company maintains station equipment and systems reliably, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, quality work activities, which effectively ready the plant for operation until the next planned outage.

Q. PLEASE DISCUSS THE COMPANY'S NUCLEAR GENERATING SYSTEM PERFORMANCE DURING THE PERIOD JANUARY 2008 THROUGH DECEMBER 2008.

A. Overall, our nuclear plants operated extremely well, supplying almost half of the power used by our customers during 2008. The Company's seven nuclear units operated at a system average capacity factor of 91.50% during the test period, which was the fourth highest capacity factor for a five refueling outage year. In addition, Oconee Unit 3 and Catawba Unit 2 set capacity factor records of 101.94% and 102.88%, respectively. McGuire Unit 2 ended a 475.98 day breaker-to-breaker run when it began its refueling outage in March 2008. In 2008, the Electric Power Research Institute ranked Catawba Nuclear Station as the third most thermally efficient nuclear power plant in the United States. In addition, the Nuclear Energy Institute ("NEI") recognized two Duke Energy programs with its Top Industry Practice ("TIP") Awards. In the community relations category, the Company was honored for 40 years of a formal nuclear community relations program. In the material and services category, Catawba's high-density polyethylene ("HDPE") piping project was honored. Catawba participated as the pilot plant for this project, which used this piping for the complete replacement of a metallic service water system. Completion of this project has resulted in substantially improved performance at a lower capital and maintenance cost because HDPE is not subject to corrosion or fouling.

The system average nuclear capacity factor has been above 90% for nine consecutive years. As I testified above, the achieved test year system nuclear capacity factor was 91.50%. In general, refueling requirements, maintenance requirements, prudent maintenance practices and NRC operating requirements impact the availability of the Company's nuclear system. The Company's nuclear performance has improved dramatically over the course of the years of operating its nuclear fleet. In particular, improved reliability and lower forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet as discussed above.

In an effort to continue this trend, the nuclear organization is placing additional focus on pre-outage planning and milestone adherence through a fleet-wide approach to outage planning. An example of the emphasis put on this effort in 2008 is the Company's creation of a scheduled Outage Improvement Team, which is assigned the task of maximizing scheduled outage predictability without compromising safety and reliability.

IV. NUCLEAR GENERATION COSTS AND CHALLENGES

Q. WHAT ARE THE SIGNIFICANT COSTS IMPACTING OPERATIONS AND MAINTENANCE EXPENSES FOR NUCLEAR OPERATIONS?

A. Operations & Maintenance ("O&M") expenditures for the Company's nuclear facilities are made up of both fuel and non-fuel items. In 2008, Duke Energy Carolinas' nuclear fleet had the lowest total operating cost for the industry, as compared to other large fleet operators, based on Electric Utility Cost Group ("EUCG") cost and performance results. EUCG is an industry group that provides member utilities a high-level industry view of their own station performance in relation to the industry. The Company's 2008 average total operating cost, which includes operating and maintenance, administration and fuel costs, was $19.26/megawatt-hour. During the test period, approximately 26% of the required O&M expenditures for the nuclear fleet were fuel related. A complete discussion of nuclear fuel costs in the test period can be found in Company Witness Geer's testimony filed with this Commission in Docket No. E-7, Sub 875.

Non-fuel items comprise the remainder of O&M expenditures for the nuclear fleet. Nuclear power plant operations are very labor intensive and therefore, a significant portion of O&M costs are related to internal and contracted labor. As a result of the Company's increased ownership interest in the Catawba Nuclear Station, O&M costs will increase approximately $17 million annually. Company Witness Stillman addresses the accounting treatment for deferral of certain of these costs. The Company expects to experience continued upward pressure on these ongoing labor costs. In addition, Duke Energy Carolinas expects labor costs to increase approximately $7 million annually due to workforce increases necessary to comply with the U.S. Nuclear Regulatory Commission's revision to its 10 CFR Part 26 rule ("the fatigue rule"). The fatigue rule places restrictions on the number of hours covered personnel may work at a nuclear facility. The revisions are intended to enhance fitness for duty ("FFD") for personnel at nuclear power plants and include new requirements for work hour limits, break limits and minimum time-off between shifts for work groups that perform covered work.

The Company has incurred additional expenses for the purposes of augmenting our existing workforce pipeline development programs to address our aging workforce. Since 2006, the Company has spent approximately $1 million annually on pipeline program expenses for development of our future engineering and skilled nuclear workforce. These programs currently include the Spartanburg Community College and Engineering Intern programs. Duke Energy Carolinas partnered with Spartanburg Community College ("SCC") to develop an Associate's Degree Program in Radiation Protection Technology. This two year program at SCC provides a steady source of radiation protection technician candidates. Likewise, the Engineering Intern Program assures a pipeline of replacement engineers by providing internships to regional university engineering students. Due to the demand for skills and age demographics, additional programs are being considered for development of nuclear operators and maintenance technicians in partnership with Gaston College. Expenses for these additional programs are expected to be commensurate with existing costs.

Other significant non-fuel costs are NRC fees that nuclear owners and operators pay annually pursuant to (1) Part 170, which covers review of applications for new licenses, renewal applications, amendment requests, and inspections, and (2) Part 171, which provides for recovery of regulatory and other generic costs. These fees are expected to increase in 2009. In March 2009, the NRC published its proposed FY2009 Fee Rule in the Federal Register (74 FR 9130) indicating (1) an increase in the hourly rate for Part 170 fees for both the reactor and materials programs and (2) an increase in the Part 171 annual license fee that nuclear operators pay per reactor. The reactor license fee is expected to be retroactive to the beginning of the government fiscal year beginning October 2008. The increased NRC fees as currently proposed, along with increases in required INPO and NEI fees, will cost the Company in excess of $5 million annually. Other non fuel-costs include project-related costs and material and employee expenses.

Q. WHAT INITIATIVES HAS THE COMPANY TAKEN TO INCREASE EFFICIENCIES IN NUCLEAR OPERATIONS?

A. The Company uses competitive benchmarking, long-range planning, work prioritization tools and other processes to continuously improve operational and cost performance. Over the years, efficiencies have been gained from the implementation of common policies, practices and procedures across the Duke Energy Carolinas nuclear fleet. In addition, efficiencies are sought through incorporation of industry best practices. Currently, nuclear generation is working closely with major supplemental workforce providers to increase the number of local workers being utilized across the nuclear fleet, when individuals with needed skills are available. Traditionally, the nuclear industry has heavily utilized workers who travel from site to site to provide outage and other supplemental labor. These workers are typically eligible for per diem living expenses when their permanent home is greater than fifty miles from the assigned work location. This initiative serves to improve the local economy and reduce nuclear operations costs. Overall, these efforts result in improved fleet reliability and efficiency on a cost per KW generated basis.

Q. WHAT CHALLENGES DOES DUKE ENERGY CAROLINAS FACE AS TO ITS NUCLEAR OPERATIONS?

A. Despite the success of the Company's efficiency initiatives, we continue to face upward pressure on O&M costs including escalation of labor costs, as discussed above. Duke Energy Carolinas is working with community colleges in North Carolina and South Carolina to offer training programs to help attract and prepare the needed, skilled workforce. In addition, the costs to perform maintenance work necessary to address reliability and regulatory concerns are increasing due to rising costs for materials and supplies.

As Witness Trent testified, one of the most significant challenges facing our industry is the cost and technological obstacles of compliance with anticipated climate change legislation. Nuclear energy emits zero greenhouse gases, has a demonstrated safety record, it is efficient and economical, and the basic technology is available today. Therefore, maintaining our existing nuclear fleet and adding additional nuclear capacity is critical to realistically attaining significant levels of carbon emissions reduction.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	STEPHEN G. DE MAY
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Stephen G. De May, and my business address is 526 South Church Street, Charlotte, North Carolina 28202. I am Senior Vice President, Treasurer and Chief Risk Officer of Duke Energy Corporation ("Duke Energy"), the parent of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"). I am also an officer of Duke Energy Carolinas.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Arts degree in Political Science from the University of North Carolina in Chapel Hill, North Carolina, and a Master of Business Administration degree from the McColl School of Business at Queens University in Charlotte, North Carolina. I am a Certified Public Accountant ("CPA") in the state of North Carolina and I am a member of the American Institute of Certified Public Accountants and the North Carolina Association of Certified Public Accountants.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. My professional work experience began in 1986 with the public accounting firm of Price Waterhouse (now PricewaterhouseCoopers) and, subsequently, Deloitte, Haskins and Sells (now Deloitte & Touche), where my work focused on tax accounting and consulting for a variety of clients, including C-corporations, S-corporations, partnerships, and high-net-worth individuals. In 1990, I joined Crescent Resources Inc., a then-wholly-owned real estate development subsidiary of Duke Power Company (a predecessor company to today's Duke Energy) where I was responsible for real estate accounting and finance. In 1994, I moved to the Treasury and Corporate Finance department where I have held, except for a two-year period of time, various positions of increasing responsibility. The two-year exception was for the majority of 2004 and 2005, during which time I had the lead responsibility for developing and managing Duke Energy's energy and regulatory policies. I was named to my current position in February 2009.

Q. PLEASE DESCRIBE YOUR DUTIES AS SENIOR VICE PRESIDENT, TREASURER AND CHIEF RISK OFFICER.

A. As Senior Vice President, Treasurer and Chief Risk Officer, I am responsible for treasury and risk management-related services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "Company"). Under my supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. My responsibilities include managing Duke Energy's and its subsidiaries' credit ratings and relationships with the major credit rating agencies, commercial banks and the capital markets. I am responsible for overall risk management oversight of Duke Energy through the identification, quantification, monitoring and reporting of financial, market and credit risks across the enterprise. My responsibilities also encompass finance-related due diligence for major capital expenditure proposals as well as corporate merger, acquisition or divestiture transactions. Finally, my responsibilities include the oversight and administration of investments supporting Duke Energy's pension and retirement benefit plans and nuclear decommissioning trust funds.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE PUBLIC UTILITY COMMISSIONS?

A. I have not previously testified before this Commission. I have filed testimony on behalf of Duke Energy Ohio, Inc. with the Public Utility Commission of Ohio in 2008 in support of an electric distribution general rate case and in 2007 in support of a gas distribution general rate case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address Duke Energy Carolinas' credit quality, capital structure and cost of capital. I will also discuss Duke Energy Carolinas' current credit ratings, the forecast of the Company's capital needs and its financial objectives.

II. CREDIT QUALITY, CAPITALIZATION, AND COST OF CAPITAL

Q. HOW DO THE CREDIT RATING AGENCIES AND OTHERS ASSESS CREDIT QUALITY?

A. Duke Energy Carolinas' creditworthiness is an assessment by the credit rating agencies and other creditors of its financial strength, including its ability to raise capital and meet its future financial obligations, and its ability to withstand changes in its business environment. Many qualitative and quantitative factors go into such an assessment. Qualitative aspects may include Duke Energy Carolinas' regulatory climate, its track record for delivering on its commitments, the strength of its management team, its operating performance, and the strength of its service area. Quantitative measures are primarily based on operating cash flow and focus on Duke Energy Carolinas' ability to meet its fixed obligations (such as interest expense) on the basis of internally-generated cash and the level at which Duke Energy Carolinas maintains debt leverage in relation to its generation of cash. Interest coverage ratios and the percentage of debt to total capital are examples of quantitative measures. Creditors and credit rating agencies generally view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. WHAT IS DUKE ENERGY CAROLINAS' PROPOSED CAPITAL STRUCTURE?

A. Duke Energy Carolinas' proposed capital structure is 47.0% long-term debt and 53.0% equity. Although the specific debt/equity ratio will vary according to financial activity (for example, as occurred in November 2008 after the Company had a major debt offering, the ratio will tilt slightly in the direction of greater debt), the 47/53 ratio is consistent with the Company's financial objectives. According to the March 31, 2009 "Monthly Financial Report" that is provided to the North Carolina Utilities Commission, Duke Energy Carolinas capital structure was approximately 47.5% long-term debt and 52.5% equity as of that date. Furthermore, I believe that as of the date of this filing, Duke Energy Carolinas' capital structure will be approximately 47.0% debt and 53.0% equity. I will further address Duke Energy Carolinas' capital structure later in my testimony.

Q. WHAT EFFECT DOES CAPITAL STRUCTURE AND RETURN ON EQUITY HAVE ON CREDIT QUALITY?

A. Capital structure and return on equity are important components of credit quality. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (e.g., debt principal and interest) of the business have been paid. Because these investors are the last to receive surplus earnings and cash flows, it is their capital that is most at risk if the company suffers a downturn in business or general financial conditions. This dynamic of equity investors receiving "residual" earnings and cash flows provides debt investors a measure of protection. Therefore, the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality. In addition, the allowed return on equity is a key component in the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for the capital they have at risk while at the same time the cash flow generated helps to protect debt holders. A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support strong credit quality. Strong credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs.

Q. DO YOU BELIEVE THAT DUKE ENERGY CAROLINAS' PROPOSED CAPITAL STRUCTURE HAS AN ADEQUATE EQUITY COMPONENT TO ENABLE DUKE ENERGY CAROLINAS TO ACHIEVE THE COMPANY'S FINANCIAL STRENGTH AND CREDIT QUALITY OBJECTIVES?

A. Yes. Duke Energy Carolinas' equity component, as requested in this case, enables it to maintain its current credit ratings and financial strength and flexibility. This level of equity enables Duke Energy Carolinas to tolerate the volatility of different business cycles while also providing a cushion to the Company's lenders and bondholders. Duke Energy Carolinas is in a period of significant capital investment necessary to provide cost-effective, safe, environmentally-compliant, and reliable service to its customers. The magnitude of its capital needs dictates the need for a strong equity component of the Company's capital structure in order to assure access to capital funding at reasonable terms.

Q. IS THE COMPANY'S PROPOSED CAPITAL STRUCTURE CALCULATED ON A BASIS CONSISTENT WITH HOW THE CREDIT RATING AGENCIES CALCULATE THE COMPONENTS OF DEBT AND EQUITY?

A. No. The credit rating agencies will calculate the Company's capital structure from publicly filed financial statements. In calculating the debt component of capital structure, the credit rating agencies will include short-term debt and current maturities of long-term debt and then impute pro-forma debt amounts to include in their capital structure calculations for long-term fixed obligations (which they consider to be "debt equivalents"). Examples of "debt equivalents" would include certain operating lease obligations, long-term purchased power agreements, and under-funded pension plan obligations. Therefore, credit rating agency calculations of capital structure typically result in a higher debt component than is produced under the Commission's methodology. This increased leverage imputed by the credit rating agencies reinforces the need for a strong equity component in Duke Energy Carolinas' capital structure.

Q. WHAT IS DUKE ENERGY CAROLINAS' AVERAGE COST OF LONG-TERM DEBT?

A. Duke Energy Carolinas' weighted-average cost of long-term debt for the test period is 5.83%.

Q. WHAT IS DUKE ENERGY CAROLINAS' COST OF EQUITY?

A. Dr. James Vander Weide, who has testified separately, indicates that the Company's cost of equity is 12.3%. As Company witness Trent testified, the Company fully supports Dr. Vander Weide's analysis and has proposed in this case that the Commission approve a return on common equity at that level in recognition of the Company's capital requirements and risk profile. Nevertheless, in light of the extraordinarily bad economic conditions currently being experienced by our customers, in this proceeding Duke Energy Carolinas has elected to calculate the revenue requirement and resulting rates requested using a return on common equity at a lower level – 11.5% instead of 12.3%. The Company believes that approval by the Commission of this approach will send a positive signal to the financial community that this Commission is not ignoring the Company's future capital needs and risks, while at the same time mitigating the impact of the requested rate increase on customers.

III. DUKE ENERGY CAROLINAS' CURRENT CREDIT RATINGS

Q. HOW ARE DUKE ENERGY CAROLINAS' OUTSTANDING SECURITIES CURRENTLY RATED BY THE CREDIT RATING AGENCIES?

A. As of the date of this testimony, Duke Energy Carolinas' outstanding debt is rated by Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as follows:

Rating Agency	S&P	Moody's
Secured Debt Rating	A	A2
Senior Unsecured Rating	A-	A3
Ratings Outlook	Positive	Stable

Q. PLEASE EXPLAIN WHAT IS MEANT BY THESE CREDIT RATINGS FOR DUKE ENERGY CAROLINAS' DEBT?

A. Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong.

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-" is at the lower end of the category. Moody's credit rating assignments use the numbers "1", "2", and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P, respectively.

Q. WHAT IS MEANT BY A "STABLE OR POSITIVE OUTLOOK"?

A. A rating outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). A "Stable Outlook" means the credit ratings are not likely to change whereas a "Positive Outlook" means the credit ratings may be raised based on the rating agency's view of potential changes to economic or fundamental business conditions.

Q. WHEN WERE DUKE ENERGY CAROLINAS' CURRENT CREDIT RATINGS ESTABLISHED?

A. Duke Energy Carolinas' current credit ratings were established by S&P in May 2007 and by Moody's in April 2006. The positive ratings outlook was assigned by S&P to Duke Energy Carolinas' ratings in September 2008, while the stable ratings outlook was assigned by Moody's in January 2008.

Q. WHAT FACTORS CAUSED S&P TO CHANGE ITS RATINGS OUTLOOK IN SEPTEMBER 2008 AND MOODY'S TO CHANGE ITS RATINGS OUTLOOK IN JANUARY 2008?

A. As stated in S&P's September 26, 2008 research update at the time of the outlook revision from stable to positive, the outlook revision "reflects the potential for higher ratings in the next nine to twelve months, provided credit metrics remain buoyant and Duke Energy continues to achieve favorable regulatory outcomes that provide for the timely recovery of its sizable utility construction program." Moody's changed its outlook from positive to stable on January 18, 2008 stating that the previously assigned positive rating outlook "largely incorporated a view that the financial performance would improve over the next several years." However, "given the company's September 2007 announcement regarding its capital investment plans and the intention to finance that plan largely with debt, Duke Energy's key financial credit metrics are no longer expected to improve and, most likely, will deteriorate over the next few years". As a result, Moody's changed the outlook to stable and further stated "this financial metric erosion is most notable at Duke Energy Carolinas, which we believe will represent a majority of the capital investment plans over the near-term".

Q. HAVE THE CREDIT RATING AGENCIES RAISED ANY CONCERNS ABOUT DUKE ENERGY CAROLINAS?

A. The credit rating agencies have identified several important issues in their evaluation of the credit quality of Duke Energy Carolinas. Although they acknowledge that the regulatory environments in which the Company operates have been generally supportive of credit quality, in its October 3, 2008 summary report on Duke Energy Carolinas, S&P did note that the rate case settlement approved by the North Carolina Utilities Commission in 2007 was "an arrangement that is not considered constructive for credit quality in light of the Company's substantial capital spending program during the next three to five years to address system and load growth". The rating agencies have also recognized the challenges of managing a substantial capital investment program, the prospects for more stringent environmental legislation, as well as capital spending requirements for new generation and environmental compliance which necessitate timely financing and capital cost recovery to support the Company's strong financial profile. In general, however, the rating agencies expect that the Company's regulatory relationships will continue to support long-term credit quality with recovery for prudently incurred costs and expenses.

Q. HAVE THE RATING AGENCIES DISCUSSED THE IMPORTANCE OF TIMELY RECOVERY OF FINANCING AND CAPITAL COSTS IN THE ASSESSMENT OF A COMPANY'S CREDITWORTHINESS?

A. Yes, they have. The rating agencies have long considered the ability to maintain strong cash flows as one of the primary determinant of creditworthiness. As an example, in its March 9, 2009 article titled "Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings", S&P stated the following:

> Innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why Standard & Poor's Ratings Services views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding as beneficial to utility creditworthiness.
>
> ...While we recognize the potential economic and political consequences of attempting to significantly raise utility rates during a recession, we believe that from a credit perspective,

> management must work to limit uncertainty in the recovery of a *utility's investment. In addition, we believe it must address the* issue of rate case lag, especially when engaged in a sizable capital expenditure program. A regulatory jurisdiction that recognizes the importance of cash flow in its decision making process enhances the utility's creditworthiness.

I believe constructive ratemaking will help support Duke Energy Carolinas' creditworthiness as they help to address the issue of regulatory lag during this period of substantial capital investment.

Q. WHAT CONSTRUCTIVE RATEMAKING MECHANISMS IS DUKE ENERGY CAROLINAS ASKING FOR IN THIS CASE THAT YOU BELIEVE WILL HELP SUPPORT ITS CREDITWORTHINESS?

A. Most important will be the overall rate relief and return on equity granted, and the timeliness of the Commission's final order. In addition, however, I believe that: (1) approval of the Company's request for recovery of its financings costs related to the Cliffside Steam Station modernization project construction work-in-progress ("CWIP") through the inclusion of this CWIP in rate base, (2) recovery of the deferred costs associated with the acquisition of additional ownership in the Catawba Nuclear Station and the addition of environmental control equipment at the Allen Steam Station, and (3) the ability of the Company to successfully update its costs and rate base through the date of the hearing in this case will be received positively by credit rating agencies and the financial community, as it will improve the Company's cash flow position. Notwithstanding these mechanisms, execution upon the Company's significant capital plan will continue to create regulatory lag, and the risks such lag engenders, under North Carolinas' existing rate making statutes.

Q. WHY IS IT IMPORTANT FOR DUKE ENERGY CAROLINAS TO HAVE STRONG INVESTMENT-GRADE CREDIT RATINGS?

A. Strong investment-grade credit ratings provide Duke Energy Carolinas with greater financial flexibility, lower debt financing costs and greater access to the capital markets. Strong credit ratings are essential to being able to raise debt capital on reasonable terms, under various market conditions, to fund infrastructure requirements and to refinance maturing debt.

To assure reliable and cost effective service, Duke Energy Carolinas must plan and initiate projects years before they are required to be operational. This is the nature of capital-intensive industries like electric utilities. The Company must be able to finance such projects without interruption through their lengthy design and construction phases, regardless of capital market conditions. Capital markets can exhibit extreme volatility, as we have recently witnessed, and Duke Energy Carolinas must be capable of financing its needs throughout such periods. Lack of access to capital can force interruption of capital projects to the long-term detriment of customers. Strong investment-grade credit ratings provide Duke Energy Carolinas with greater assurance of continued access to the capital markets on favorable terms during periods of extreme volatility.

Recent debt market conditions have illustrated the importance of strong investment-grade credit ratings such as the A- / A3 senior unsecured ratings that Duke Energy Carolinas currently enjoys. As Anthony Ianno, Managing Director, Global Risk Capital Markets, Morgan Stanley stated in his prepared remarks at the "FERC Technical Conference on Credit and Capital Issues affecting the U.S.

Electricity Power Industry" on January 13, 2009, the costs for issuing debt in the investment-rate debt market have increased substantially:

> Before the credit crisis, investors would calculate the expected return, by adding the credit spread associated with default risk, to the risk-free rate. This equation has now changed.
>
> In addition to default risk, investors are asking that return accrue the premium for volatility, a premium for liquidity, and an excess return in the form of a new-issue premium. The lower the credit rating, the greater the premium investors are expecting.

Mr. Ianno also addressed the importance of strong investment-grade credit ratings in terms of companies' ability to access the debt markets when needed (see De May Exhibit No. 1, page 6, to my testimony). As Mr. Ianno's materials indicated on the page titled "2008 Utility Issuance by Credit Rating", of the $13.6 billion of issuance since the Lehman bankruptcy, only 35% was issued by companies rated in the "BBB" category. The remaining 65% came from utilities, like Duke Energy Carolinas, that were rated in the "A" category. This compares to a split for 2008 utility issuance up to the date of the Lehman bankruptcy of 52% from "A" rated utilities and 48% from "BBB" rated utilities. Company witness Fetter provides further testimony regarding the impact of the recent financial crisis on access to credit and cost of debt and the corresponding need for strong credit ratings.

Q. DO YOU EXPECT THIS FILING TO HAVE ANY SUBSTANTIAL IMPACT ON THE COMPANY'S CREDIT RATINGS?

A. No, assuming the Commission approves a constructive outcome. As I previously stated, the rating agencies perceive the regulatory environments in which Duke Energy Carolinas operates as being supportive of credit quality. As evidence of the rating agencies assessment of these regulatory environments, in its November 2008 assessment of regulatory climates for United States investor-owned utilities, S&P assessed the regulatory jurisdictions in which Duke Energy Carolinas operates as either "credit supportive" (North Carolina) or "more credit supportive" (South Carolina). These assessments were based on a five-category scale that included "least credit supportive", "less credit supportive", "credit supportive", "more credit supportive", and "most credit supportive".

S&P laid out the factors it utilizes to assess regulation in its November 26, 2008 Criteria for Utilities, "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry". The critical success factors S&P delineated include consistency and predictability of decisions; support for recovery of fuel and investment costs; history of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and support for a reasonable cash return on investment. Furthermore, S&P stated that regulation is the most critical aspect that underlies regulated utilities' creditworthiness stating "regulatory decisions can profoundly affect financial performance. S&P's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness."

Assuming a constructive outcome is achieved, including the approval of the constructive ratemaking mechanisms I previously discussed, I do not believe that this proceeding will adversely impact Duke Energy Carolinas' credit ratings.

IV. DUKE ENERGY CAROLINAS' CAPITAL REQUIREMENTS

Q. WHAT ARE DUKE ENERGY CAROLINAS' CAPITAL REQUIREMENTS DURING THE 2009-2011 TIME PERIOD?

A. Duke Energy Carolinas faces substantial capital needs over the next several years in order to satisfy environmental and other regulatory requirements, refurbish, replace and upgrade aging infrastructure, construct or acquire needed generation resources, and invest greater amounts in energy efficiency. The Company's capital requirements are projected to be approximately $8.6 billion during the period 2009-2011. This amount consists principally of $8.0 billion in projected construction and nuclear fuel costs and approximately $700 million in debt retirements.

Q. HOW WILL DUKE ENERGY CAROLINAS' CAPITAL REQUIREMENTS BE FUNDED?

A. Duke Energy Carolinas' capital requirements are expected to be partially funded from internal cash generation of approximately $5.7 billion with the balance of approximately $2.9 billion funded principally from the issuance of debt (both short-term and long-term) and equity contributions from Duke Energy. Equity funding requirements, to the extent they are required to maintain an appropriate capital structure for Duke Energy Carolinas, may be satisfied through either a reduction in the dividends that Duke Energy Carolinas pays to its parent or through the receipt of equity contributions from its parent. During the period 2009-2011, Duke Energy Carolinas expects to receive approximately $500 million in equity contributions from its parent to support its extensive capital needs over the next several years.

Q. HOW DOES DUKE ENERGY CAROLINAS' PROJECTION OF CAPITAL EXPENDITURES COMPARE WITH RECENT HISTORICAL LEVELS OF CAPITAL EXPENDITURES?

A. As previously discussed, Duke Energy Carolinas' projected capital expenditures for the next three years is approximately $8.0 billion. This exceeds by approximately $2.0 billion the level spent by the Company in the prior three year period ending with the test period. The higher level of capital expenditures reflects new generation projects and environmental expenditures that the Company must incur to continue to provide cost-effective, safe, environmentally-compliant, and reliable service to its customers.

Q. DESCRIBE DUKE ENERGY CAROLINAS' DIVIDEND POLICY WITH RESPECT TO PAYING DIVIDENDS TO ITS PARENT.

A. Duke Energy Carolinas must, over time, pay dividends of approximately 70-80% of earnings to its parent to support dividend payments to Duke Energy's shareholders. In any given year, Duke Energy Carolinas will vary the level of dividend payments based upon its capital needs and as needed to properly maintain its desired capital structure.

V. DUKE ENERGY CAROLINAS' FINANCIAL OBJECTIVES

Q. WHAT ARE DUKE ENERGY CAROLINAS' FINANCIAL OBJECTIVES?

A. Duke Energy Carolinas' overall financial objective is to maintain financial strength with assured and reasonable access to low cost capital in order to continue to provide cost-effective, safe, adequate, environmentally-compliant and reliable service to our customers. Specific financial objectives necessary to maintain financial strength include: (a) maintaining at least a 53% common equity for Duke Energy Carolinas on a financial capitalization basis; (b) maintaining current credit ratings; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital.

Q. DO YOU BELIEVE THAT DUKE ENERGY CAROLINAS' CUSTOMERS WILL BENEFIT IF DUKE ENERGY CAROLINAS IS ABLE TO ACHIEVE ITS FINANCIAL OBJECTIVES?

A. Yes, our customers will benefit from the financial objectives that we have established. As previously discussed, maintaining a strong capital structure with a sufficient return on equity helps to ensure safer returns to debt holders which translates into higher credit quality, allowing Duke Energy Carolinas the financial flexibility to attract capital from the debt and equity markets as needed. The benefits of these financial objectives include not only lower debt financing costs, but also greater assurance of access to the capital markets as needed, thus improving Duke Energy Carolinas ability to maintain a safe, reliable, and low cost level of customer service for its customers, even in a recessionary period such as we are currently experiencing.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

De May Exhibit 1

Morgan Stanley

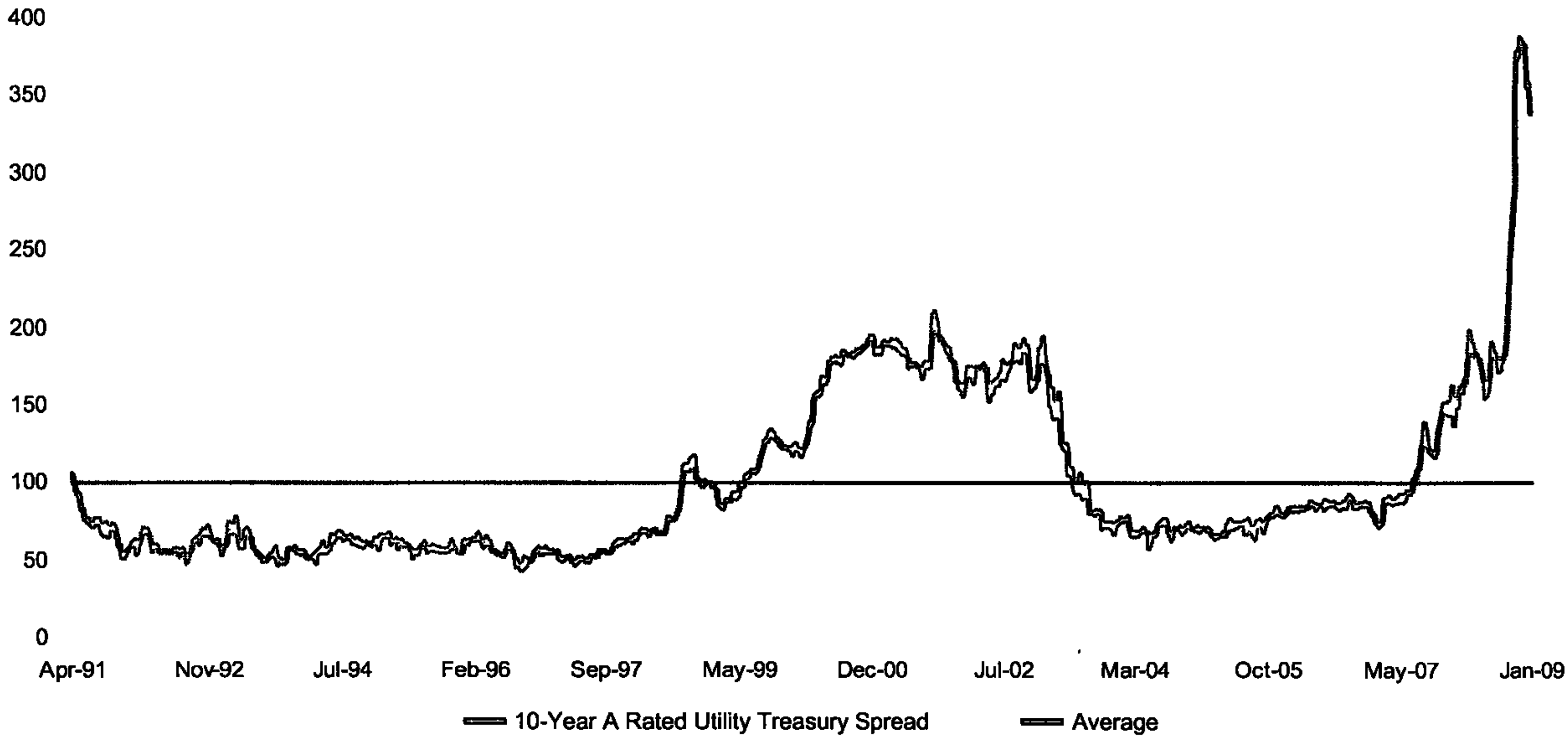
Credit and Capital Issues Affecting the Electric Power Industry

Anthony Ianno
Managing Director
Head of Energy & Utilities Global Risk Capital Markets

January 13, 2009

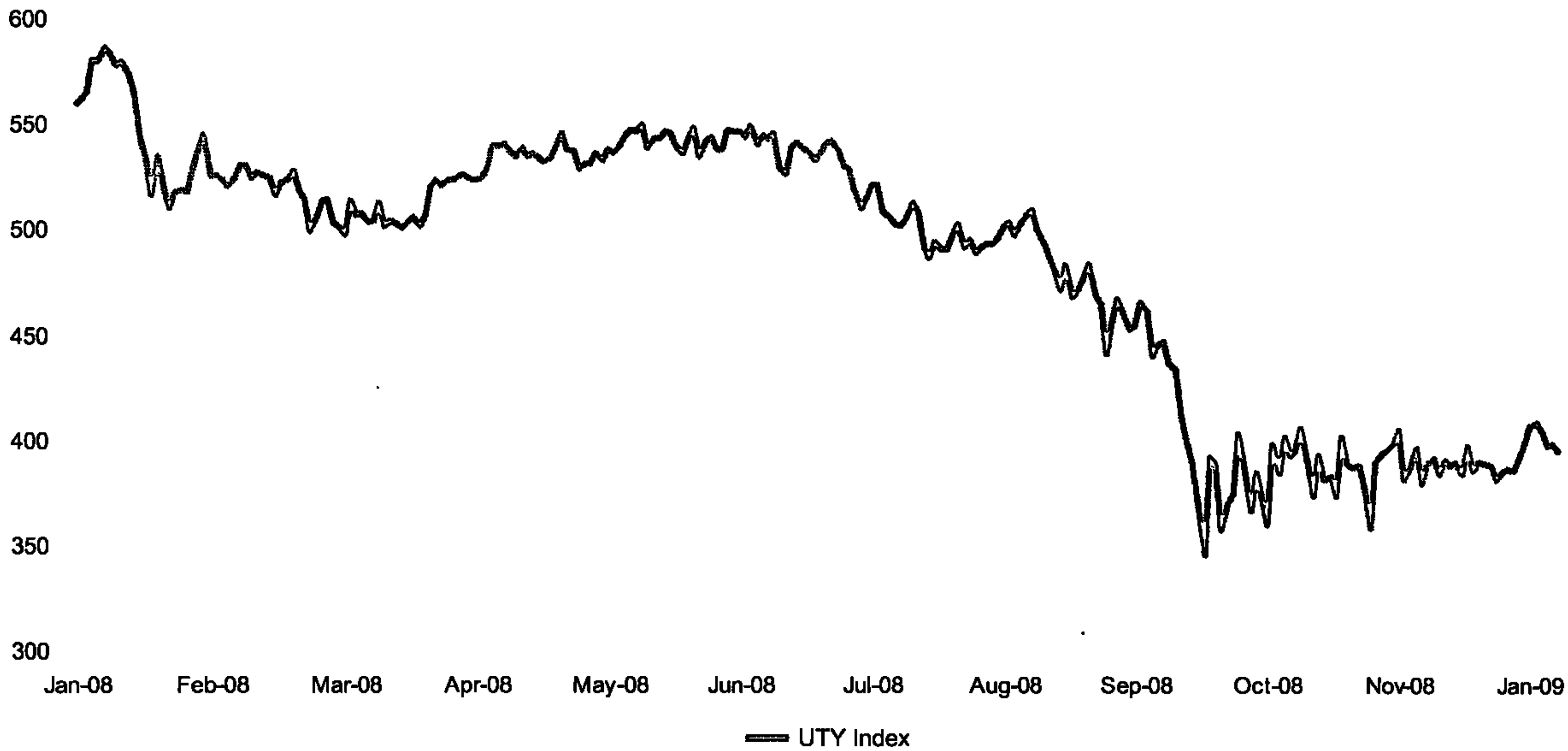
Debt Spreads Have Increased Dramatically

10-Year Utility Secondary Trading Spreads



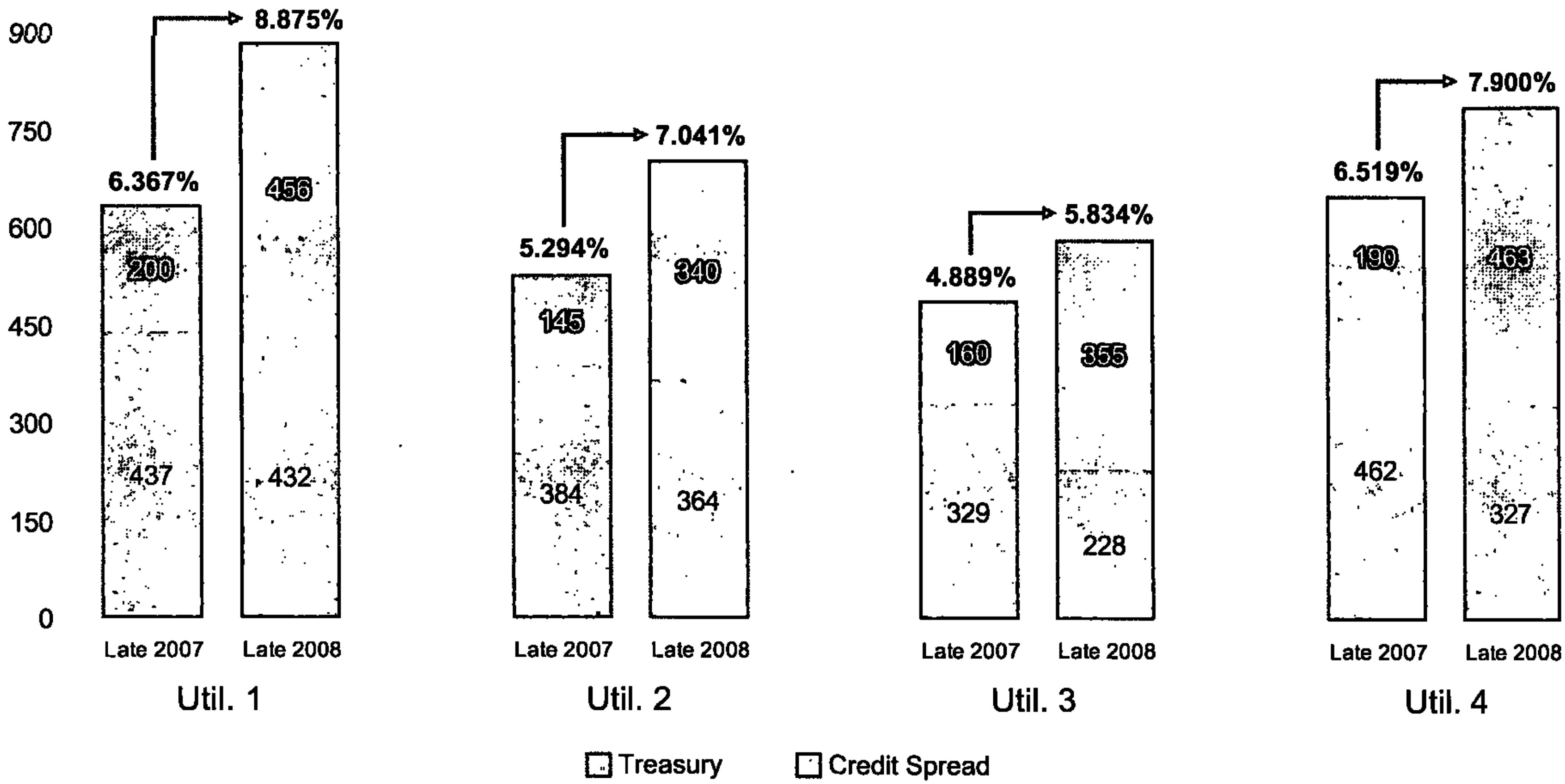
Utility Stock Index Performance

2008 – Present



All-in Funding Costs Have Increased

Investors Focused On Yield; Concessions Significant



Morgan Stanley

How Do Investors Think About Risk?

Current pricing is well outside of norms associated with cyclical downturns, indicating systemic risk pricing rather than consideration of historical default probabilities

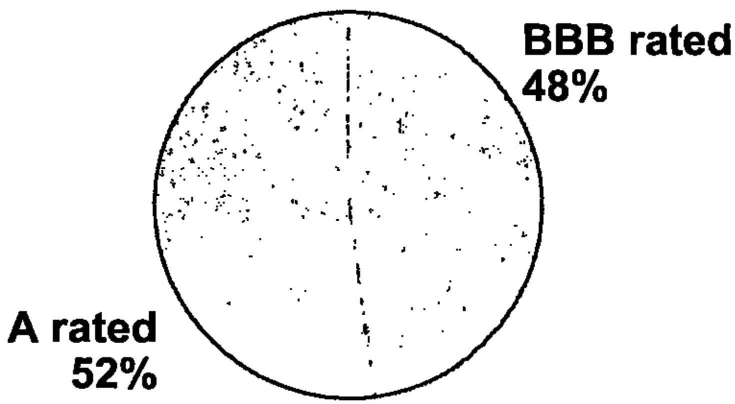
Old Equation		New Equation
Bond Yield	→	Bond Yield
=		=
Risk Free Rate		Risk Free Rate
+		+
Default Risk		Default Risk
		+
		Volatility Risk
		+
		Liquidity Risk
		+
		Excess Return

2008 Utility Issuance by Credit Rating

Before and After the Lehman Bankruptcy

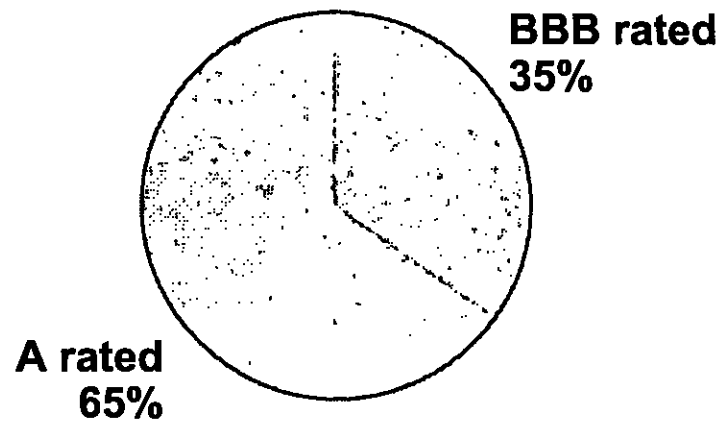
Pre-Lehman Bankruptcy

$36.2Bn Issued between Jan 1 and Sept 14



Post-Lehman Bankruptcy

$13.6Bn Issued between Sept 15 and Dec 31



BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	))))	DIRECT TESTIMONY OF STEVEN M. FETTER FOR DUKE ENERGY CAROLINAS, LLC

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Duke Energy Carolinas LLC ("Duke Energy Carolinas" or the "Company").

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC").

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UNFETTERED.

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH FITCH?

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

Q. HOW LONG WERE YOU EMPLOYED BY FITCH?

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

Q. HOW DOES YOUR EXPERIENCE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience as a Commissioner on the Michigan PSC and my subsequent professional experience analyzing the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in setting rates and also in determining appropriate terms and conditions of service for regulated utilities. These are among the factors that enter into the process of utility credit analysis and formulation of individual company credit ratings. It is undeniable that a utility's credit ratings significantly affect the ability of a utility to raise capital on a timely basis and upon reasonable terms.

Q. HAVE YOU PREVIOUSLY GIVEN TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have testified on numerous occasions before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, construction work in progress and other interim rate recovery structures, utility securitization bonds, and nuclear energy. I have testified before the North Carolina Utilities Commission ("North Carolina Commission" or "Commission") in Duke Energy Carolinas' last rate case, Docket No. E-7, Sub 828, which concluded with a settlement approved by this Commission.

My full educational and professional background is presented in Fetter Exhibit 1.

II. EXECUTIVE SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In this testimony, I explain my opinion that while Duke Energy Carolinas currently maintains strong "A" category credit ratings – which I believe represents the appropriate rating target for regulated utilities and their regulators – a constructive resolution by the Commission in this rate case is important for the Company to maintain that appropriate credit rating status. The Commission's decision will come, as I explain, during a period of extreme turmoil within the

U.S. financial sector and capital markets. Accordingly, a less supportive decision in this case that would be perceived by the financial community as negative could weaken the Company's current credit profile. Such negative action could increase the potential that the Company would be downgraded out of the 'A' category. Such a downgrade could negatively affect the Company's ability to access the capital markets fully and, even if access were not limited, a rating in the 'BBB' category would increase Duke Energy Carolinas' costs during a period of substantial capital investment as detailed in the direct testimony of Company witness Stephen G. De May. Avoiding the higher financing costs that would accompany such potential negative rating action would minimize future rate impacts on customers and should serve to maintain investor interest in the Company.

III. FINANCIAL CRISIS

Q. WOULD YOU PROVIDE YOUR THOUGHTS ABOUT THE CURRENT FINANCIAL CRISIS FACING THE U.S. UTILITY INDUSTRY?

A. Yes. With the capital markets currently experiencing an historic, worldwide financial melt-down with a resulting severe economic recession, I believe it is important for regulators to factor into their decision-making the negative effects that would occur if a regulated utility were to be downgraded from the 'A' rating category into the 'BBB' category, including ultimately increased rates for consumers. The U.S. stock market experienced its third-worst year in more than a century in 2008, with the S&P 500 and the Dow Jones Industrial Average down 38.5% and 33.8%, respectively. No fewer than fifteen U.S. banks failed in 2008, including the well-publicized bankruptcy of Lehman Brothers on September 15, 2008, the largest bankruptcy in U.S. history. The changes on Wall Street mean that there will be less capital available for companies seeking debt and equity financing – and, unlike the broader corporate industrial sector which can delay capital investment in times of duress, electric utilities carry a public responsibility to expend capital when needed to ensure safe and reliable service to customers.

I understand that the recent economic turmoil resulted in some utilities within the 'BBB' category experiencing difficulty in accessing the capital markets at any cost. Even when capital is available, it is often at significantly higher costs and upon less favorable terms and conditions. As Moody's reported in a January 16, 2009 report entitled, "Near-term Bank Credit Facility Renewals To Be More Challenging For U.S. Investor-Owned Electric and Gas Utilities":

> Dramatic changes in the financial markets during 2008 have materially changed the banking environment for utilities going forward, which will make upcoming credit facility renewals significantly more challenging. . . . Those banks that do remain will be constrained in both their ability and inclination to provide traditional credit, especially at the relatively low pricing levels and on the liberal terms and conditions that prevailed prior to mid-2008.

Even with its ratings in the 'A' category from S&P and Moody's, Duke Energy Carolinas recently warned that access to financing is not a given amidst the current and unprecedented levels of market volatility:

> ...although [parent] Duke Energy has continued to issue commercial paper, there can be no assurance that such markets will continue to be a reliable source of short-term financing ... If *current levels of market disruption and volatility continue or* worsen, Duke Energy Carolinas may be forced to meet its other liquidity needs by further drawing upon contractually committed lending agreements primarily provided by global banks, although there is no assurance that the commitments made by lenders under Duke Energy's master credit facility will be available if needed due to the recent turmoil throughout the financial services industry.

> This could require Duke Energy Carolinas to seek other funding sources. However, under such extreme market conditions, there can be no assurance other funding sources would be available or sufficient.[1]

Q. HAVE OTHER INDUSTRY LEADERS OFFERED SIMILAR CAUTIONS?

A. Yes. During the January 13, 2009 Federal Energy Regulatory Commission ("FERC") Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, regulators, industry representatives, and banks all agreed that the financial crisis is having a more dramatic impact on lower rated utilities. W. Paul Bowers, the Executive Vice President and Chief Financial Officer of Southern Company, noted that although the financial crisis has led to increases in debt and equity risk premiums for all utilities, these increases have been more consistently applied to utilities that do not hold high credit ratings, resulting in significantly higher cost of debt capital for 'BBB' category utilities as compared to 'A' rated utilities. Mr. Bowers' views were supported by data presented by Anthony Ianno, Managing Director and Head of Energy & Utilities Global Risk Capital Markets at Morgan Stanley, which showed that investment in 'BBB' rated utilities dropped approximately 13% in the period after the Lehman Brothers bankruptcy, while investment in 'A' rated utilities rose by the same margin. Such data clearly show that, in the wake of the financial crisis, investor interest has been increasingly directed toward less risky 'A' rated utilities. As Chairman Garry Brown of the New York Public Service Commission ("NYPSC") noted at the FERC conference, "there is a clear relationship between a utility's bond rating

[1] Duke Energy Carolinas LLC 2008 Form 10-K (March 13, 2009).

and its ability to borrow at a reasonable cost, particularly in times of economic distress as we are now facing."

As I alluded to earlier, electric utilities do not possess the strategic option of substantially cutting back their operations during difficult economic times. Despite facing the reality of having rates out of line with decreasing sales, as well as growing uncollectible billed amounts, utilities must provide safe, efficient, and reliable service to their customers notwithstanding dysfunction within the financial markets. The electric utility sector is one of the most capital-intensive sectors in the country, and utilities must continue to make significant capital expenditures to maintain reliability, replace aging infrastructure, and meet longer-term load growth requirements. As NYPSC Chairman Brown further noted, "Large capital programs . . . *make it very important that electric utilities continue* to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital."

Although I have long testified that regulated electric utilities should seek to maintain a corporate credit rating no lower than 'BBB+', with an ultimate target of the 'A' category, based upon the events of the past year, I have begun to question whether a 'BBB+' rating remains adequate to ensure market access when needed upon reasonable terms, along with protecting ratepayer interests.

Q. WHY IS THAT?

A. Since September 2008, yield spreads on bonds with default risk have moved significantly higher, as opposed to falling yields on U.S. Treasury bonds ("Treasuries"). Data for 2008 shows that for 10-year unsecured utility debt, by the end of the year, the spread over Treasuries for new issues became 356 basis points for 'A' rated debt and 492 basis points for 'BBB+' rated debt. This compares to similar debt that six months earlier was trading slightly below ('A' rated) or above ('BBB+' rated) 200 basis points over Treasuries.[2] Moreover, with regard to longer-term debt, a comparison of basis point spreads between 'A' and 'Baa' rated Moody's utility bond indices and 30-year Treasuries shows a widening of spreads at an alarming rate since the beginning of the financial crisis. In December 2007, the amount over Treasuries for 'A' rated utility bonds was 163 basis points, and the amount over Treasuries for 'Baa' rated utility bonds was 198 basis points. As of December 2008, the amount over Treasuries for 'A' rated utility bonds was 365 basis points, and the amount over Treasuries for 'Baa' rated utility bonds was 524 basis points. The difference between 'A' and 'Baa' rated utility bond yields thus totaled 159 basis points (a growth of 124 basis points since December 2007).[3]

Q. HASN'T THE SITUATION IMPROVED SINCE THE END OF 2008?

A. While spreads have tightened since the end of 2008, volatility in the equity markets remains high. What I believe is important to take away from capital market events over the past eight months is that the negative effects from the current financial crisis on the overall economy will not be transitory nor quick to turn around. And the utility sector, even if positively "stimulated" with federally supported infrastructure spending, must still deal with delinquent accounts and uncollectibles growing across virtually the entire regulated energy sector, deeply eroded pension plan values, soaring health care funding requirements, and

[2] Barclay's Capital, Chart: *10-year Unsecured Utility A vs. 10-year Unsecured Utility BBB+*, as of January 5, 2009.
[3] Data from U.S. Treasury Department, Mergent Bond Record, and Bloomberg.

financing activity that is subject to greater volatility with regard to both availability and cost. The negative events during the Fall of 2008 illustrate clearly that 'BBB' category utilities are much more vulnerable than 'A' category utilities when capital markets are in a state of upheaval, with diminished investor interest and higher costs to serve customers the two major threats to operational efficiency and financial stability.

IV. CREDIT RATINGS

Q. TO PROVIDE CONTEXT FOR DUKE ENERGY CAROLINAS' CURRENT CREDIT RATING LEVEL, COULD YOU PROVIDE A GENERAL DESCRIPTION OF THE RATING PROCESS?

A. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Corporate rating designations of S&P basically have "AA", "A" and "BBB" category ratings within the investment-grade ratings sphere, with "BBB-" as the lowest investment-grade rating and "BB+" as the highest non-investment-grade rating. Comparable rating designations of Moody's at the investment-grade dividing line are "Baa3" and "Ba1", respectively.

Corporate credit ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties to gauge both the short-term and longer-term health and viability of a company.

Q. CAN YOU PROVIDE A BRIEF DISCUSSION ON WHY CREDIT RATINGS ARE IMPORTANT FOR REGULATED UTILITIES AND THEIR CUSTOMERS?

A. Yes. It is a well-established fact that a utility's credit ratings have a significant impact as to whether that utility will be able to raise capital on a timely basis and upon reasonable terms. As respected economist Charles F. Phillips stated in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) **they determine, in part, the cost of new debt, since both the interest charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases**; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[4] [Emphasis supplied.]

Thus, the lower a regulated utility's credit rating, the more the utility will have to pay to raise funds from debt and equity investors to carry out its capital-intensive

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[4] *Phillips, Charles F., Jr.,* The Regulation of Public Utilities, *Arlington, Virginia: Public Utilities Reports, Inc.,* 1993, at p. 250. See also Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

operations. In turn, the ratemaking process factors the cost of capital for both debt and equity into the rates that consumers are required to pay. Therefore, a utility with strong credit ratings is not only able to access the capital markets on a more timely basis at reasonable rates, it also is able to share the benefit from those attractive interest rate levels with customers since cost of capital gets factored into utility rates. This is especially true for a company like Duke Energy Carolinas, which is planning to expend significant levels of capital in order to increase and modernize its generation portfolio and take steps to ensure continuing reliability of service to customers.

I also note that Duke Energy Carolinas' strong "A" credit profile places the Company in a position to withstand negative events such as significant stress caused by damage from storms or other unforeseeable setbacks.

Q. WOULD YOU ELABORATE ON THIS POINT?

A. Yes. Two of my experiences while serving as an energy consultant illustrate the differing capabilities between an electric utility holding an 'A' rating versus one at the 'BBB' level: Consolidated Edison Company of New York ("Con Ed") has long held superior ratings within the utility industry. On September 11, 2001, Con Ed held an 'A+' corporate credit rating. In the face of the catastrophic terrorist events of that day, Con Ed was able to immediately initiate one of the largest infrastructure recovery efforts any industry has ever faced. It was able to do so without seeking special treatment from its suppliers or its lenders. The company's credit rating and outlook never faltered as it proceeded to bring businesses in Lower Manhattan back to full function.

Contrast that with Entergy New Orleans, a utility that had seen its corporate credit rating improve from 'BBB' with a CreditWatch Negative to that same rating with a Stable outlook. Then, In August 2005, Hurricane Katrina hit, devastating the utility's infrastructure and customer base. In the face of resistance from contractual counterparties to provide supplies and assistance, Entergy New Orleans soon filed for bankruptcy, opening the way for its parent company, Entergy Corporation, to provide $200 million in funds to support the beginning of the long road to reorganization and recovery.[5]

These examples came long before the current financial market crisis, but they demonstrate that a credit profile in the 'A' category provides substantial flexibility for a regulated utility's management to respond to customer needs while respecting investor interests.

Q. PLEASE DESCRIBE THE QUALITATIVE FACTORS USED BY THE RATING AGENCIES.

A. The most important qualitative factors include regulation, management and business strategy, and access to energy, gas and fuel supply with recovery of associated costs.

Q. PLEASE EXPLAIN YOUR THOUGHTS ON THE IMPORTANCE OF REGULATION WITHIN THE CREDIT RATINGS PROCESS?

A. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses

[5] Interestingly, with a new regulatory direction in New York State, Con Ed's corporate rating has been downgraded twice since 2001, but still resides in the 'A' category at 'A-'. Entergy New Orleans emerged from bankruptcy in June 2007 with an investment-grade 'BBB-' corporate credit rating.

including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Since the announcement of California's restructuring plan in 1994, regulation has become an even more important factor as the nature of a utility's responsibilities in providing energy services to customers has undergone dramatic change. In some states, industry restructuring was the result of plans formulated by the state legislature. In other states, the regulators, rather than the legislators, have determined the nature and pace of restructuring, or whether it would occur at all.

This situation thus affects utility investors' decisions because, before major investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly changing industry and that their decision-making will be fair and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. HAVE THE RECENT FINANCIAL AND OPERATIONAL CHALLENGES FACING ALL UTILITY MANAGEMENTS INCREASED THE FOCUS ON THE ACTIONS OF UTILITY REGULATORS BY THE FINANCIAL COMMUNITY?

A. Yes, without a doubt. Events like the fraudulent actions of Enron, the California restructuring debacle with negative impacts spilling over into neighboring states, and Hurricanes Katrina and Rita have tested the financial standing of the utility sector like never before. With the extreme turmoil in the financial markets during the past several months, we appear to have come to another "never before" moment. Liquidity, or access to cash when needed, has always been a major issue for regulated utilities, but it has leaped to the forefront of utility financial and operational concerns and has driven structural decisions on the part of utility executives.[6] For example, on September 19, 2008, Constellation Energy Group Inc. ("CEG"), which had held a solid credit rating in the "A" category as recently as 2004 but is now at "BBB" (Watch Negative) at S&P and 'Baa3' (Review for Downgrade) at Moody's, agreed to a merger with MidAmerican Energy Holdings Co. ("MidAmerican"), in large part due to its need for an immediate cash infusion through MidAmerican's purchase of $1 billion of CEG preferred stock.[7] In mid-December 2008, CEG backed out of the MidAmerican merger, at least in part due to investor sentiment that the deal had been done at a fire-sale price due to the

[6] See, for example, "Utilities' Plans Hit by Credit Markets," Wall Street Journal, October 1, 2008 ("Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or to come up with *different – and often more costly – ways of raising cash.*").
[7] See Fitch Research: "Fitch Affirms Constellation Energy & Baltimore G&E on MidAmerican Acquisition," September 18, 2008 ("This upfront cash infusion...alleviates the liquidity pressures facing CEG and Fitch believes it will restore confidence in CEG as a counterparty.")

credit crisis, and instead agreed to sell half of its nuclear power business to Electricité de France SA for $4.5 billion.[8]

Thus, while regulation has always garnered the attention of Wall Street, years ago it seemed to be a focus only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory, legislative and political factors that could affect a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years. And of course the recent stresses within the credit markets I referred to earlier, with their huge financial repercussions, have increased the stakes substantially beyond regulators merely having to adjust their policies to deal with flawed restructuring initiatives.

Q. DO THE RATING AGENCIES AGREE THAT UTILITY REGULATORS AND THEIR DECISION-MAKING CONTINUE TO BE IMPORTANT WITHIN THE CREDIT RATING PROCESS?

A. Yes. S&P highlighted the continuing importance of regulation to the financial community in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry":

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the

[8] See "EDF Beats Out Buffett in Energy Deal," Wall Street Journal, December 17, 2008.

> regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Consistent with these views, S&P recently explained how recovery mechanisms can play a key role in providing a regulated utility with timely recovery of prudent expenditures, thereby helping to mitigate the negative effects from regulatory lag:

> ... there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly large rate base increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. ... the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume-based charges, the greater the support for credit quality.[9]

Q. IS IT REASONABLE TO EXPECT THAT THESE GENERAL STATEMENTS ABOUT THE IMPORTANCE OF REGULATION FIND SPECIFIC APPLICABILITY WITH REGARD TO THE POLICIES OF THE NORTH CAROLINA COMMISSION?

A. Yes, very much so. Virtually every time a rating agency modifies or affirms a utility credit rating, mention is made of the regulatory body within the relevant jurisdiction and how its policies are factored into the rating determination. For example, in a report issued on the Company in October 2008, S&P stated:

> The regulatory environments in North Carolina and South Carolina are generally constructive and supportive of credit quality, with

[9] S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009.

> adequate returns on equity ..., the ability to earn on approved capital structures that have more than 50% equity, recovery of prudently incurred fuel costs, and the requirement to share 90% of bulk power marketing profits with public assistance, education, and economic programs, and a portion credited to ratepayers. ... [Duke Energy Carolinas' positive outlook] incorporates the expectation that [parent] Duke Energy will remain focused on its regulated utility operations and will successfully pursue ongoing constructive regulatory outcomes in all its jurisdictions that will provide support to the proposed capital spending program.[10]

Similarly, Moody's recently stated that the Company operates within a "[g]enerally supportive regulatory environment," which represents "a material credit positive." In Moody's opinion, "the regulatory framework is considered fully developed, predictable and stable with a high expectation of timely recovery of prudently incurred costs and investments."[11]

Accordingly, it is not surprising that the North Carolina and South Carolina regulators are graded highly by utility industry commentators. Regulatory Research Associates ("RRA"), a respected utility regulatory analysis firm based in Jersey City, New Jersey, maintains a ranking of regulatory jurisdictions based upon an investor's perspective. North Carolina is currently ranked by RRA among the top six state jurisdictions, with South Carolina among the top fourteen. Of note, RRA praised the North Carolina Commission's "constructive rate frameworks that provide a degree of certainty with regard to the recovery of expenditures related to legislatively mandated emission reductions at coal-fired generation facilities" and constructive legislation requiring the Commission to pre-determine a utility's decision to build a baseload generating plant and projected costs.

[10] S&P Research: "Duke Energy Carolinas LLC," October 3, 2008.
[11] Moody's Research: "Duke Energy Carolinas, LLC," January 30, 2009.

A positive perception of regulation within a utility's jurisdiction by the financial community is factored into credit rating analysis and can assist a company in maintaining or improving its credit ratings.

Q. COULD YOU PLEASE DESCRIBE THE QUANTITATIVE FACTORS USED BY THE RATING AGENCIES?

A. Yes. Financial performance continues to be a very important element in credit rating analysis. Credit rating agencies and fixed-income analysts utilize analytical ratios to understand the credit profile of a utility, with S&P publishing the indicative ratios that it uses, in part, to assess utility risk: Funds from Operations ("FFO") Interest Coverage; Funds from Operations / Total Debt; and Total Debt / Total Capital.[12] Rating agencies may adjust these key ratios to reflect imputed debt and interest-like fixed charges related to operating leases and certain other off-balance sheet obligations. I note that, while all three ratios are important, S&P has noted the agency's greater emphasis on cash flow measures, or the first two ratios: "Cash flow analysis is the single most critical aspect of all credit rating decisions."[13]

Building upon those indicative ratios, S&P has explained how it views the interplay between quantitative and qualitative factors. As part of its utility credit rating process, S&P arrives at a "Business Risk Profile" designation that it considers in concert with its "Financial Risk Profile." Financial Risk is assessed based upon indicative ratios for the three key credit measures cited above; the

[12] S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.
[13] S&P Research: "A Closer Look at Ratings Methodology," November 13, 2006.

weaker the Business Risk Profile designation, the stronger the financial ratios must be in order to support an investment-grade rating.[14]

Q. WHAT DOES S&P'S BUSINESS RISK PROFILE DESIGNATION REFLECT?

A. The Business Risk Profile designation reflects S&P's assessment of qualitative factors such as regulation, markets, operations, competitiveness, and management. Interestingly, on November 30, 2007, S&P announced that it had inserted utility companies into its longstanding "Corporate Ratings" matrix, and that this new framework superseded its prior "Utility Financial Targets" matrix. Thus, while previously S&P had measured business profiles on a '1' (meaning very strong) to '10' (meaning very weak) scale, going forward S&P will rank business risk as 'Excellent', 'Strong', 'Satisfactory', 'Weak', or 'Vulnerable'. However, it is important to note that S&P stated in its recent report announcing the change that "Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles."[15] Thus, analysts using this new matrix will be faced with the seemingly anomalous situation that a utility designated as 'Strong' (or the second highest of the five business risk profile rankings) will actually reside within the lower half of all U.S utility business risk profiles, basically at a below average level. Similarly, under S&P's new framework, Financial Risk Profiles will be designated as 'Minimal', 'Modest', 'Intermediate', 'Aggressive', or 'Highly Leveraged', words that are not necessarily accurate descriptions of the strategies adopted by

[14] S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.
[15] *Ibid.*

regulated utilities or the actions taken by their regulators. Duke Energy Carolinas has been assigned an S&P Business Risk Profile of 'Excellent', and a Financial Risk Profile of 'Intermediate'.16 As shown in S&P's Table 1 printed below, the Company's risk profile would normally equate to a credit rating of "A". Since S&P does not assign ratings solely on this matrix, but uses it as a guide, most outcomes will fall within one notch on either side of the indicated rating. Duke Energy Carolinas' current corporate credit rating of "A-" stands within this range.[17]

Table 1

Business Risk/Financial Risk

Financial Risk Profile

Business Risk Profile	Minimal	Modest	Intermediate	Aggressive	Highly leveraged
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

Q. WHY IS S&P'S METHODOLOGY MEANINGFUL TO YOU?

[16] S&P Research: "U.S. Electric Utility Companies, Strongest to Weakest," January 5, 2009.
[17] *Ibid.*; S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.

A. I believe that S&P's methodology helps facilitate a general understanding of how a credit rating agency carries out the process of formulating a credit rating and the factors that go into such a determination.[18]

IV. ANALYSIS OF DUKE ENERGY CAROLINAS' CREDIT RATINGS

Q. WHAT CREDIT RATINGS DOES DUKE ENERGY CAROLINAS CURRENTLY HOLD?

A. As I stated, Duke Energy Carolinas' credit ratings are strong. The Company's current corporate credit ratings are "A-" from S&P with a Positive Outlook and "A3" from Moody's with a Stable Outlook.

Q. YOU FOCUS ABOVE ON S&P'S RATING METHODOLOGY. CAN YOU DISCUSS HOW S&P'S METHODOLOGY CAN PROVIDE GUIDANCE TO THE COMMISSION IN THIS CASE?

A. Yes I can. With my background as former head of the Fitch utility ratings practice, I certainly appreciate that the credit rating process goes beyond the mere matching up of ratios with rating ranges. I do believe, however, that the S&P Financial Risk Indicative Ratios (table 2) combined with the business and financial risk profiles (in table 1) are very helpful with regard to indicating rating trends. By combining both quantitative factors (in the form of financial ratios) with qualitative assessments (in the form of a business risk profile ranking), S&P is able to provide useful tools to assess potential credit rating outcomes for individual utility companies.

[18] I focus here on S&P's ratings methodology, as opposed to those at Moody's or Fitch, due to the greater transparency of S&P's ratings process owing to its explanation of the methodology and how it is implemented in published reports. See, for example, S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007, and S&P Research: "U.S. Electric Utility Companies, Strongest to Weakest," January 5, 2009.

Table 2

Financial Risk Indicative Ratios – U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 – 60	4.0 - 6.0	25 – 40
Intermediate	25 – 45	3.0 - 4.5	35 – 50
Aggressive	10 – 30	2.0 - 3.5	45 – 60
Highly leveraged	Below 15	2.5 or less	Over 50

Q. HOW DO YOU VIEW DUKE ENERGY CAROLINAS WITHIN THE CONTEXT OF THE S&P MATRIX?

A. I would expect that a constructive and timely decision in this proceeding, as well as in the upcoming rate case in South Carolina, would allow the Company to maintain an S&P Business Risk Profile of 'Excellent' and a Financial Risk Profile of 'Intermediate'. In that case, I expect that the Company should be able to maintain its current "A-" corporate credit rating.

Q. IF A DOWNGRADE WERE TO OCCUR, BASED ON YOUR EXPERIENCE AT FITCH, COULD YOU OPINE AS TO HOW LONG IT WOULD BE BEFORE DUKE ENERGY CAROLINAS COULD REGAIN ITS "A" CATEGORY RATING?

A. It is impossible to predict when the Company would be able to regain an "A" category rating, but I wish to emphasize that it would NOT be a bounce-back scenario. The rating agencies do not take a rating action, either up or down, with the view that the rating could return to its prior level in a day, or a week, or even a month. A rating determination is a prospective opinion based upon prevailing and forecasted factors. If the agencies were to take an action to downgrade Duke Energy Carolinas, it would be because they believed that a material change in qualitative and/or quantitative factors existed. If financial performance was forecasted to return to prior levels in short order, it is likely such downgrade was based on a perception of a sustained change in either business risk or regulatory environment.

Q. HAVE THE RATING AGENCIES EXPRESSED ANY CONCERNS ABOUT THE COMPANY'S CURRENT SITUATION?

A. Yes. I note, however, that even though the capital markets are currently in disarray, I would not want to suggest any dire predictions for Duke Energy Carolinas, since the Company does hold attractive ratings from both S&P and Moody's. That said, S&P has noted that the settlement of the Company's last rate case was "not considered constructive for credit quality in light of the company's substantial capital spending program during the next three to five years to address system and load growth," and that, if the Company were to proceed with its proposed nuclear construction without regulatory support or increase its focus on unregulated activities, the Positive ratings outlook could be reduced to Stable.[19] Similarly, Moody's has aired concerns about risks associated with more stringent environmental legislation and with constructing a new coal-fired generating facility; more frequent regulatory proceedings; the challenges of managing a substantial capital investment program; and modestly declining financial metrics.

[19] S&P Research: "Duke Energy Carolinas LLC," October 3, 2008.

The agency noted that a downgrade could occur if the Company's "financial profile were to decline more severely," if "overall business and operating risk" were to increase, such as due to more stringent environmental regulations, or if adverse legal proceedings were to permanently harm the Company's financial strength.[20]

VI. CONCLUSION

Q. DO YOU HAVE CONCLUDING THOUGHTS?

A. Yes. What is clear across the entire utility sector is that a strong "A" rating is more important today than in the past to ensure access to capital at reasonable cost and upon reasonable terms. The financial crisis, along with the fact that Duke Energy Carolinas has a need for substantial financing given its projected capital investment program, makes maintaining the Company's current 'A-' / 'A3' ratings even more important to ensure that ratepayers receive highly reliable utility service at reasonable prices. In view of the extreme volatility and stress that has characterized the utility sector during the past ten months, my advice to utility companies, investors and regulators alike is that nothing should be taken for granted within the current financial climate. Based upon the track records of both the Company and this Commission, the rating agencies have exhibited confidence that each of them will undertake actions within their control so as to maintain a positive environment within which Duke Energy Carolinas will be able to continue to operate in a way that fairly balances the interests of all stakeholders within the utility process. I encourage such a positive path.

[20] Moody's Research: "Duke Energy Carolinas, LLC," January 30, 2009.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

STEVEN M. FETTER

1489 W. Warm Springs Rd. -- Ste. 110
Henderson, NV 89014
732-693-2349
RegUnF@gmail.com
www.RegUnF.com

Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Henderson, NV

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Lead Independent Director; Chairman, Governance and Nominating Committee; Member, Audit; Previous Chairman, Audit Committee and Compensation Committee), National Regulatory Research Institute, Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant – NYNEX – New York, Ameritech -- Chicago, Weatherwise USA – Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner – Michigan Public Service Commission – Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney – National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)
- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)
- Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)
- The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)
- Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)
- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)
- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 909

In the Matter of	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	JAMES H. VANDER WEIDE
For Adjustment of Rates and Charges Applicable	)	FOR
to Electric Service in North Carolina	)	DUKE ENERGY CAROLINAS, LLC

INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is James H. Vander Weide. I am Research Professor of Finance and Economics at the Fuqua School of Business of Duke University. I am also President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PRIOR ACADEMIC EXPERIENCE.

A. I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, and then Professor.

Since joining the faculty I have taught courses in corporate finance, investment management, and management of financial institutions. I have taught a graduate seminar on the theory of public utility pricing and lectured in executive development seminars on the cost of capital, financial analysis, capital budgeting, mergers and acquisitions, cash management, short-run financial planning, and competitive strategy. I have served as Academic Program Director of executive education programs at the Fuqua School of Business, including the Duke Advanced Management Program, the Duke Executive Program in Telecommunications, the Duke Competitive Strategies in Telecommunications Program, and the Duke Program for Manager Development for managers from the former Soviet Union. I have conducted seminars and training sessions on financial analysis, financial strategy, cost of capital, cash management, depreciation policies, and short-run financial planning for a wide variety of U.S. and international companies.

In addition to my teaching and executive education activities, I have written research papers on such topics as portfolio management, the cost of capital, capital budgeting, the effect of regulation on the performance of public utilities, the economics of universal service requirements, and cash management. My research papers have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business,* and *Computers and Operations Research.*

Q. HAVE YOU PREVIOUSLY TESTIFIED ON FINANCIAL OR ECONOMIC ISSUES?

A. Yes. As an expert on financial and economic theory, I have testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in approximately 400 cases before numerous federal, state, and international regulatory and judicial bodies. My resume is attached as Appendix 1. In North Carolina, I have testified on the required rate of return on equity in numerous proceedings, most recently on behalf of Duke Energy Carolinas in Docket No. E-7, Sub 828.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "the Company") to prepare an independent appraisal of Duke Energy Carolinas' cost of equity, and to recommend to the North Carolina Utilities Commission ("the Commission") a rate of return on equity that is fair, that allows Duke Energy Carolinas to attract capital on reasonable terms, and that allows Duke Energy Carolinas to maintain its financial integrity.

I. SUMMARY OF TESTIMONY

Q. HOW DO YOU ESTIMATE DUKE ENERGY CAROLINAS' COST OF EQUITY?

A. I estimate the cost of equity for Duke Energy Carolinas in two steps. First, I apply several standard cost of equity methods to market data for a large group of utility companies of comparable risk. Second, I adjust the average cost of equity for my comparable companies for the difference between the financial risk of those companies in the marketplace and the financial risk implied by the rate making capital structure for Duke Energy Carolinas.

Q. WHY DO YOU APPLY YOUR COST OF EQUITY METHODS TO A LARGE GROUP OF COMPARABLE RISK COMPANIES RATHER THAN SOLELY TO DUKE ENERGY CAROLINAS?

A. I apply my cost of equity method to a large group of comparable risk companies because standard cost of equity methodologies such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured.[1] Since these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methodologies to a large sample of comparable companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methodologies to a group of comparable companies. In utility regulation, the practice of using a group of comparable companies, called the comparable company approach, is further supported by the United States Supreme Court standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk.[2]

Q. WHAT COST OF EQUITY DO YOU FIND FOR YOUR COMPARABLE COMPANIES IN THIS PROCEEDING?

A. On the basis of my studies, and as summarized in the table below, I find that the cost of equity for my comparable companies is equal to 11.1 percent. This conclusion is based on my application of standard cost of equity estimation techniques–the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM–to a broad group of companies of comparable risk. As noted below, the cost of equity for these comparable companies must be adjusted to reflect the higher financial risk associated with Duke Energy

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[1] The problem of difficult-to-measure inputs is especially acute for Duke Energy Carolinas because, as a subsidiary of Duke Energy Corporation ("Duke Energy"), its stock is not publicly traded.

[2] *See Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Hope Natural Gas Co.*, 320 U.S. at 603.

Carolinas' rate making capital structure, which produces a cost of equity equal to 12.3 percent for Duke Energy Carolinas.

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	COST OF EQUITY
Discounted Cash Flow	12.4%
Ex Ante Risk Premium	11.4%
Ex Post Risk Premium	10.9%
Historical CAPM	9.8%
DCF-based CAPM	11.1%
Average	11.1%
Cost of Equity Reflecting Higher Financial Risk of Duke Energy Carolinas' Rate Making Capital Structure	12.3%

Q. YOU NOTE THAT THE COST OF EQUITY OF YOUR COMPARABLE COMPANIES SHOULD BE ADJUSTED FOR FINANCIAL RISK. WHY IS THAT ADJUSTMENT NEEDED?

A. The cost of equity for my comparable companies depends on their financial risk, which is measured by the market values of debt and equity in their capital structures. The financial risk of my comparable companies differs from the financial risk associated with Duke Energy Carolinas' rate making capital structure. It is both logically and economically inconsistent to apply a cost of equity developed for a sample of companies with a specific degree of financial risk to a capital structure with a different financial risk. One must adjust the cost of equity for my comparable companies upward in order for investors in Duke Energy Carolinas to have an opportunity to earn a return on their investment in Duke Energy Carolinas that is commensurate with returns they could earn on other investments of comparable risk.

Q. HOW DOES DUKE ENERGY CAROLINAS' FINANCIAL RISK, AS REFLECTED IN ITS RATE MAKING CAPITAL STRUCTURE, COMPARE TO THE FINANCIAL RISK OF YOUR COMPARABLE COMPANIES?

A. Duke Energy Carolinas' rate making capital structure in this proceeding contains 47.0 percent debt and 53.0 percent equity. The average market value capital structure for my comparable group of companies contains 37.54 percent debt, 0.72 percent preferred, and 61.74 percent equity. Thus, the financial risk of Duke Energy Carolinas as reflected in its rate making capital structure is greater than the financial risk embodied in the cost of equity estimates for my comparable companies.

Q. WHAT IS THE FAIR RATE OF RETURN ON EQUITY FOR DUKE ENERGY CAROLINAS INDICATED BY YOUR COST OF EQUITY ANALYSIS?

A. My analysis indicates that Duke Energy Carolinas would require a fair rate of return on equity equal to 12.3 percent in order to have the same weighted average cost of capital as my comparable companies.

Q. DO YOU HAVE EXHIBITS ACCOMPANYING YOUR TESTIMONY?

A. Yes. I have prepared or supervised the preparation of ten schedules and five appendices that accompany my testimony.

II. ECONOMIC AND LEGAL PRINCIPLES

Q. HOW DO ECONOMISTS DEFINE THE REQUIRED RATE OF RETURN, OR COST OF CAPITAL, ASSOCIATED WITH PARTICULAR INVESTMENT DECISIONS SUCH AS THE DECISION TO INVEST IN

ELECTRIC GENERATION, TRANSMISSION, AND DISTRIBUTION FACILITIES?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. HOW DOES THE COST OF CAPITAL AFFECT A FIRM'S INVESTMENT DECISIONS?

A. The goal of a firm is to maximize the value of the firm. This goal can be accomplished by accepting all investments in plant and equipment with an expected rate of return greater than the cost of capital. Thus, a firm should continue to invest in plant and equipment only so long as the return on its investment is greater than or equal to its cost of capital.

Q. HOW DOES THE COST OF CAPITAL AFFECT INVESTORS' WILLINGNESS TO INVEST IN A COMPANY?

A. The cost of capital measures the return investors can expect on investments of comparable risk. The cost of capital also measures the investor's required rate of return on investment because rational investors will not invest in a particular investment opportunity if the expected return on that opportunity is less than the cost of capital. Thus, the cost of capital is a hurdle rate for both investors and the firm.

Q. DO ALL INVESTORS HAVE THE SAME POSITION IN THE FIRM?

A. No. Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. WHAT IS THE OVERALL OR AVERAGE COST OF CAPITAL?

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q. CAN YOU ILLUSTRATE THE CALCULATION OF THE OVERALL OR WEIGHTED AVERAGE COST OF CAPITAL?

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by .50 times 7 percent plus .50 times 13 percent, or 10.0 percent.

Q. HOW DO ECONOMISTS DEFINE THE COST OF EQUITY?

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. HOW DO ECONOMISTS MEASURE THE PERCENTAGES OF DEBT AND EQUITY IN A FIRM'S CAPITAL STRUCTURE?

A. Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market values of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q. WHY DO ECONOMISTS MEASURE A FIRM'S CAPITAL STRUCTURE IN TERMS OF THE MARKET VALUES OF ITS DEBT AND EQUITY?

A. Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. WHY DO INVESTORS MEASURE THE EXPECTED RETURN ON THEIR INVESTMENT PORTFOLIOS USING MARKET VALUE WEIGHTS RATHER THAN BOOK VALUE WEIGHTS?

A. Investors measure the expected return on their investment portfolios using market value weights because: (1) the expected return on a portfolio is calculated by comparing the expected value of the portfolio at the end of the investment period to its current value; and (2) market values are the best measure of the current value of the portfolio. From the investor's point of view, the historical cost, or book value of their investment, is generally a poor indicator of the portfolio's current value.

Q. IS THE ECONOMIC DEFINITION OF THE WEIGHTED AVERAGE COST OF CAPITAL CONSISTENT WITH REGULATORS' TRADITIONAL DEFINITION OF THE AVERAGE COST OF CAPITAL?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book values of debt and equity in a company's capital structure.

Q. DOES THE REQUIRED RATE OF RETURN ON AN INVESTMENT VARY WITH THE RISK OF THAT INVESTMENT?

A. Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q. DO ECONOMISTS AND INVESTORS CONSIDER FUTURE INDUSTRY CHANGES WHEN THEY ESTIMATE THE RISK OF A PARTICULAR INVESTMENT?

A. Yes. Economists and investors consider all the risks that a firm might be exposed to over the future life of the company.

Q. ARE THESE ECONOMIC PRINCIPLES REGARDING THE FAIR RETURN FOR CAPITAL RECOGNIZED IN ANY SUPREME COURT CASES?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*; and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* In the *Bluefield Water Works* case, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923)].

The Court clearly recognizes here that: (1) a regulated firm cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated firm will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of the same risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Court reiterates the financial soundness and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)].

The Court clearly recognizes that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

III. BUSINESS AND FINANCIAL RISKS

Q. WHAT BUSINESS AND FINANCIAL RISKS DID YOU CONSIDER IN YOUR ASSESSMENT OF THE COST OF EQUITY FOR DUKE ENERGY CAROLINAS?

A. I considered both the general business and financial risks associated with the state of the U.S. economy ("macroeconomic risks") and the specific business and financial risks associated with investing in the electric energy business of Duke Energy Carolinas.

A. MACROECONOMIC RISKS

Q. HOW DO YOU DESCRIBE THE CURRENT U.S. ECONOMIC ENVIRONMENT?

A. The U. S. economy is in the midst of the largest housing, employment, credit, and financial crisis since World War II. During the last year, housing construction has virtually halted, housing prices have collapsed, foreclosures have increased, banks have either failed or announced multi-billion dollar write-offs, unemployment has increased, and investor confidence in the health of the economy is at record lows.

Q. HAS THE CONGRESSIONAL STIMULUS PACKAGE REDUCED INVESTOR UNCERTAINTY ABOUT THE U.S. ECONOMIC ENVIRONMENT?

A. No. Because the problems in the U.S. economy are so widespread and the stimulus package will greatly increase the Federal deficit, investors are uncertain whether the stimulus package will be effective in resolving economic problems.

Q. HOW HAVE INVESTORS RESPONDED TO THE DETERIORATING U.S. ECONOMIC CONDITIONS?

A. Investors have responded by increasing their aversion to risk, reducing their leverage, increasing their demand for liquidity, and increasing their required rates of return on risky investments.

Q. WHAT EFFECT HAS THE INCREASED AVERSION TO RISK, REDUCTION IN LEVERAGE, INCREASED DEMAND FOR LIQUIDITY, AND INCREASED REQUIRED RATES OF RETURN ON RISKY STOCK AND BOND INVESTMENTS HAD ON STOCK PRICES AND INTEREST RATES?

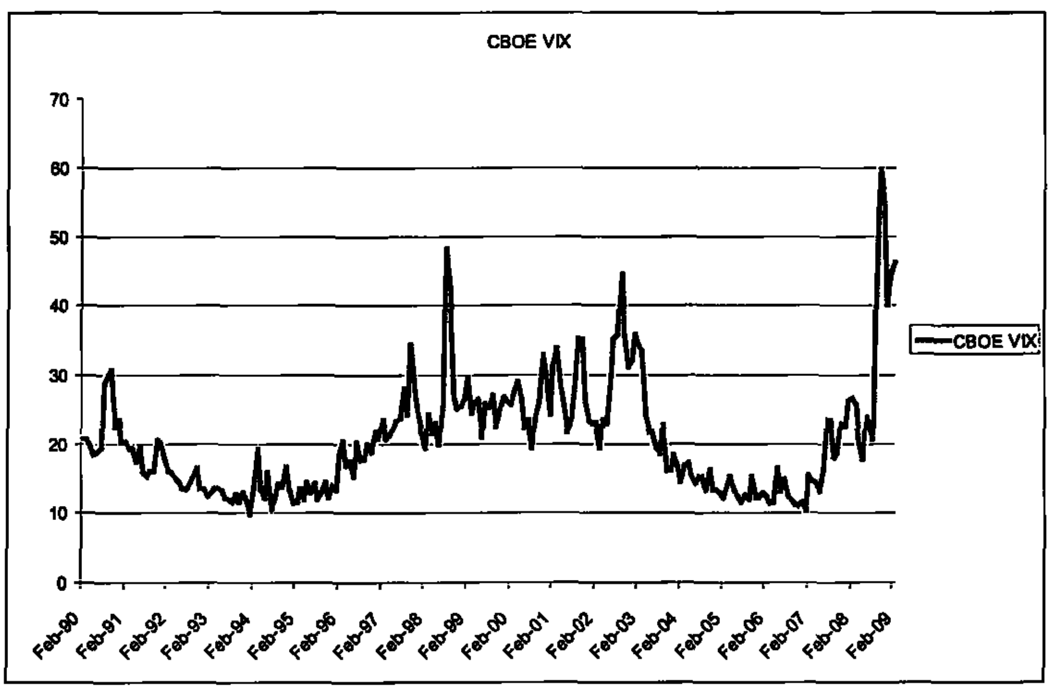
A. These factors have caused stock prices to decline by the highest percentage since The Great Depression and caused interest rates on all but the safest bond investments to increase. The S&P 500 has declined by approximately 40 percent in the past year and by approximately 50 percent since mid-2007. The stock market has not experienced declines of this magnitude since the early 1930s. Interest rates on Baa-rated utility bonds have increased from approximately

6 percent in early 2007 to approximately 8 percent in the period January to March 2009, while interest rates on high yield corporate bonds have been at double digit levels since September 2008.

Q. HAVE INCREASED RISK AVERSION, REDUCED DEMAND FOR LEVERAGE, INCREASED DEMAND FOR LIQUIDITY, AND INCREASED REQUIRED RATES OF RETURN ON RISKY STOCK AND BOND INVESTMENTS ALSO INCREASED STOCK MARKET VOLATILITY?

A. Yes. Economists generally use the Chicago Board Options Exchange ("CBOE") volatility index to measure stock market volatility. Since September 2008, the CBOE volatility index has been at its highest levels since the late 1990s.

Figure 1
CBOE Volatility Index
February 1990 — February 2009



B. BUSINESS AND FINANCIAL RISKS OF INVESTING IN ELECTRIC ENERGY COMPANIES

Q. WHAT ARE THE PRIMARY BUSINESS AND FINANCIAL RISKS FACING ELECTRIC ENERGY COMPANIES SUCH AS DUKE ENERGY CAROLINAS?

A. The business and financial risks of investing in electric energy companies such as Duke Energy Carolinas include:

1. Demand Uncertainty. Demand uncertainty is one of the primary business risks of investing in electric energy companies such as Duke Energy Carolinas. Demand uncertainty is caused by: (a) the strong dependence of electric demand on the state of the economy and weather patterns; (b) the sensitivity of demand to changes in rates; (c) the ability of customers to choose alternative forms of energy, such as natural gas or oil; (d) the ability of some customers to locate facilities in the service areas of competitors; (e) the ability of some customers to conserve energy or produce their own electricity under cogeneration or self-generation arrangements; and (f) the ability of municipalities to go into the energy business rather than renew the company's franchise. Demand uncertainty is a problem for electric companies because of the need to plan for infrastructure additions many years in advance of demand.

2. Operating Expense Uncertainty. The business risk of electric energy companies is also increased by the inherent uncertainty in the typical electric energy company's operating expenses. Operating expense uncertainty arises as a result of: (a) the prospect of increasing employee health care and pension expenses; (b) uncertainty over plant outages, the cost of purchased power, and the revenues achieved from off system sales; (c) variability in

maintenance costs and the costs of other materials, (d) uncertainty over outages of the transmission and distribution systems, as well as storm-related expenses; (e) the prospect of increased expenses for security; and (f) high volatility in fuel prices or interruptions in fuel supply.

3. Investment Cost Uncertainty. The electric energy business requires very large investments in the generation, transmission, and distribution facilities required to deliver energy to customers. The future amounts of required investments in these facilities are highly uncertain as a result of: (a) demand uncertainty; (b) the changing economics of alternative generation technologies; (c) uncertainty in environmental regulations and clean air requirements; (d) uncertainty in the costs of construction materials and labor; (e) uncertainty in the amount of additional investments to ensure the reliability of the company's transmission and distribution networks; (f) uncertainty regarding the regulatory and management structure of the electric transmission network; and (g) uncertainty regarding future decommissioning and dismantlement costs. Furthermore, the risk of investing in electric energy facilities is increased by the irreversible nature of the company's investments in generation, transmission, and distribution facilities. For example, if an electric energy company decides to invest in building a new generation plant, and, as a result of new environmental regulations, energy produced by the plant becomes uneconomical, the company may not be able to recover its investment.

4. High Operating Leverage. The electric energy business requires a large commitment to fixed costs in relation to the operating margin on sales, a situation known as high operating leverage. The relatively high degree of fixed

costs in the electric energy business arises from the average electric energy company's large investment in fixed generation, transmission, and distribution facilities. High operating leverage causes the average electric energy company's *operating income to be highly sensitive to revenue fluctuations.*

5. High Degree of Financial Leverage. The large capital requirements for building economically efficient electric generation, transmission, and distribution facilities, along with the traditional regulatory preference for the use of debt, have encouraged electric utilities to maintain highly debt-leveraged capital structures as compared to non-utility firms. High debt leverage is a source of additional risk to utility stock investors because it increases the percentage of the firm's costs that are fixed, and the presence of higher fixed costs increases the sensitivity of a firm's earnings to variations in revenues.

6. Regulatory Uncertainty. Investors' perceptions of the business and financial risks of electric energy companies are strongly influenced by their views of the quality of regulation. Investors are painfully aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric energy companies operating in those states. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Q. HAVE ANY OF THESE RISK FACTORS CHANGED IN RECENT YEARS?

A. Yes. The risk of investing in electric energy companies has increased as a result of significantly greater macroeconomic uncertainty, projected electric energy company capital expenditures, and volatility in fuel prices; greater uncertainty in the cost of satisfying environmental requirements; more volatile purchased power and off system sales prices; greater uncertainty in employee health care and pension expenses; and greater uncertainty in the expenses associated with system outages, storm damage, and security. Each of these factors puts pressure on customer rates and therefore increases regulatory risk. The Commission should recognize these higher risks and the correspondingly higher returns required by investors in setting the allowed rate of return for Duke Energy Carolinas in this proceeding.

Q. HOW DOES GREATER MACROECONOMIC UNCERTAINTY AFFECT THE BUSINESS AND FINANCIAL RISKS OF INVESTING IN ELECTRIC ENERGY COMPANIES SUCH AS DUKE ENERGY CAROLINAS?

A. Greater macroeconomic uncertainty increases the business and financial risks of investing in electric energy companies such as Duke Energy Carolinas by fundamentally increasing demand uncertainty, investment uncertainty, and regulatory uncertainty.

Q. WHY DOES MACROECONOMIC UNCERTAINTY INCREASE DEMAND UNCERTAINTY?

A. Macroeconomic uncertainty increases demand uncertainty because the demand for electric energy services depends on the state of the economy. The greater is the uncertainty regarding the state of the economy, the greater will be the uncertainty regarding the demand for energy services.

Q. HOW DOES INCREASED DEMAND UNCERTAINTY AFFECT THE UNCERTAINTY OF THE FUTURE RETURN ON INVESTMENT FOR DUKE ENERGY CAROLINAS?

A. Increased demand uncertainty greatly increases the uncertainty of the future return on investment for Duke Energy Carolinas because most of the Company's costs are fixed, while its revenues are variable. Thus, greater volatility in revenues produces greater volatility in return on investment.

Q. WHY DOES MACROECONOMIC UNCERTAINTY INCREASE INVESTMENT COST UNCERTAINTY?

A. Increased macroeconomic uncertainty greatly increases the uncertainty of investment costs for electric companies like Duke Energy Carolinas because it increases the uncertainty regarding: the demand for electric energy; the economics of alternative generating technologies; the cost of environmental regulations; the cost of construction materials and labor; and the amount of additional investment required to ensure the reliability of the company's transmission and distribution networks.

Q. WHY DOES MACROECONOMIC UNCERTAINTY INCREASE REGULATORY UNCERTAINTY?

A. Regulatory uncertainty arises because investors are not certain that regulators will be willing to set rates that allow companies an opportunity to recover their costs of service and earn a fair and reasonable return on investment. Regulatory uncertainty increases in difficult economic times because investors recognize that regulators are likely to face greater pressure to restrain rate increases in difficult economic times than in good economic times.

Q. HOW DO GREATER PROJECTED CAPITAL EXPENDITURES AFFECT THE BUSINESS AND FINANCIAL RISKS OF INVESTING IN ELECTRIC ENERGY COMPANIES SUCH AS DUKE ENERGY CAROLINAS?

A. Greater projected capital expenditures increase the business and financial risks of investing in electric energy companies such as Duke Energy Carolinas by increasing investment cost uncertainty, operating leverage, and regulatory uncertainty.

Q. WHY DO GREATER PROJECTED CAPITAL EXPENDITURES INCREASE AN ELECTRIC ENERGY COMPANY'S INVESTMENT COST UNCERTAINTY?

A. Greater projected capital expenditures increase investment cost uncertainty because investments in new generation, transmission, and distribution facilities take many years to complete. As investors found during the last electric energy investment boom of the 1980s, actual costs of building new generation, transmission, and distribution facilities can differ from forecasted costs as a result of changes in environmental regulations, materials costs, capital costs, and unexpected delays.

Q. WHY DO GREATER PROJECTED CAPITAL EXPENDITURES INCREASE OPERATING LEVERAGE?

A. As noted above, operating leverage increases when a firm's commitment to fixed costs rises in relation to its operating margin on sales. Increased capital expenditures increase operating leverage because investment costs are fixed, the investment period is long, and revenues do not generally increase in line with investment costs until the investment is entirely included in rate base. Thus, the ratio of fixed costs to operating margin increases when capital expenditures increase.

Q. WHY DO GREATER PROJECTED CAPITAL EXPENDITURES INCREASE REGULATORY UNCERTAINTY?

A. As noted above, regulatory uncertainty arises because investors are aware that regulators in some states have been unwilling at times to set rates that allow a company an opportunity to recover its cost of service, including the cost of capital. Regulatory uncertainty is most pronounced when rates are projected to increase. Greater projected capital expenditures increase regulatory uncertainty because they frequently cause rates to increase.

Q. IS DUKE ENERGY CAROLINAS PROJECTING GREATER CAPITAL EXPENDITURES OVER THE NEXT THREE YEARS?

A. Yes. Duke Energy Carolinas projects that it will spend $8 billion over the period 2009 through 2011, including significant capital expenditures in the Cliffside Unit 6 project and in new gas-fired generation units.

Q. ARE YOU FAMILIAR WITH THE CONCEPT OF "REGULATORY LAG?"

A. Yes. "Regulatory lag" refers to the delay between the time a utility's return on investment either exceeds or falls short of its cost of capital and the time rates are adjusted to narrow the gap between the utility's return on investment and its cost of capital.

Q. HOW IS A COMPANY'S RETURN ON INVESTMENT MEASURED?

A. A company's return on investment is equal to the ratio of its operating profits (that is, revenues minus operating expenses) to its investment in plant and equipment.

Q. WHAT WOULD CAUSE A UTILITY'S RETURN ON INVESTMENT TO FALL SHORT OF ITS COST OF CAPITAL?

A. A utility's return on investment will fall short of its cost of capital if either: (1) its operating expenses and investment in plant and equipment are increasing faster than its revenues; or (2) its cost of capital is increasing.

Q. ARE DUKE ENERGY CAROLINAS' OPERATING EXPENSES AND INVESTMENT IN PLANT AND EQUIPMENT LIKELY TO INCREASE FASTER THAN ITS REVENUES IN THE NEXT THREE YEARS?

A. Yes. Since Duke Energy Carolinas projects that it will spend $8 billion on capital expenditures over the period 2009 to 2011, its operating expenses and investment in plant and equipment are likely to increase faster than its revenues in the next three years.

Q. DOES REGULATORY LAG INCREASE A UTILITY'S RISK?

A. Yes. When a utility invests in new plant and equipment, it incurs the risk that its return on investment will be less than its cost of capital. Regulatory lag increases a utility's risk because it increases the likelihood that the company's return on investment will be less than its cost of capital.

Q. HOW CAN REGULATORS REDUCE THE RISK OF REGULATORY LAG?

A. Regulators can reduce the risk of regulatory lag by using forward-looking test years and including construction work in progress in rate base.

Q. DOES THE NORTH CAROLINA UTILITIES COMMISSION SET RATES BASED ON A FORWARD-LOOKING TEST YEAR?

A. No. Rates in North Carolina are based on an historical test year.

Q. CAN THE RISKS FACING DUKE ENERGY CAROLINAS AND OTHER ELECTRIC ENERGY COMPANIES BE DISTINGUISHED FROM THE RISKS OF INVESTING IN COMPANIES IN OTHER INDUSTRIES?

A. Yes. The risks of investing in electric energy companies such as Duke Energy Carolinas can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in electric energy companies are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are largely irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in the electric energy business are largely asymmetric. That is, there is little opportunity for electric energy companies to earn more than their required return, and a significant chance that they will earn less than their required return.

Q. YOU MENTION THE PROSPECT THAT ELECTRIC ENERGY COMPANIES WILL NEED TO MAKE MAJOR INVESTMENTS IN NEW GENERATION FACILITIES OVER THE NEXT TEN YEARS. WHY ARE

INVESTMENTS IN NEW GENERATION FACILITIES ESPECIALLY RISKY?

A. Investment in new generation facilities is especially risky because the required investment is large, illiquid, and irreversible; the investment horizon is unusually long; the investment and operating costs are highly uncertain; and environmental regulations may change significantly over the life of the investment. In addition, there is no consensus on the best generation option. The natural gas option has a lower investment cost and shorter investment horizon, but fuel costs are highly volatile. The coal and nuclear options have significantly lower long run expected operating costs, but a higher required investment and a longer investment horizon. Renewable energy, though desirable from an environmental standpoint, may be more expensive than other alternatives and may not produce reliable energy in peak periods. The uncertainties associated with all generation options create additional risks for electric utilities.

IV. COST OF EQUITY ESTIMATION METHODS

Q. WHAT METHODS DID YOU USE TO ESTIMATE DUKE ENERGY CAROLINAS' FAIR RATE OF RETURN ON EQUITY?

A. I used several generally accepted methods for estimating the cost of equity for Duke Energy Carolinas. These are the Discounted Cash Flow (DCF), the ex ante risk premium, the ex post risk premium methods, and the capital asset pricing model (CAPM). The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The ex ante risk premium method assumes that an investor's current expectations regarding the equity risk premium can be estimated from recent data on the DCF expected rate of return on equity compared to the interest rate on long-term bonds. The ex post risk premium method assumes that an investor's current expectations regarding the equity-debt return differential is equal to the historical record of comparable returns on stock and bond investments. The cost of equity under both risk premium methods is then equal to the interest rate on bond investments plus the risk premium. The CAPM assumes that the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

C. DISCOUNTED CASH FLOW METHOD

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \dots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_S = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the firm's stock;
$D_1, D_2 \ldots D_n$	=	Expected annual dividend per share on the firm's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, g, this equation can be solved for k, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the expected dividend yield component of the annual DCF model, and the term g is called the expected growth component of the annual DCF model.

Q. ARE YOU RECOMMENDING THAT THE ANNUAL DCF MODEL BE USED TO ESTIMATE DUKE ENERGY CAROLINAS' COST OF EQUITY?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression of the present value of future dividends if dividends are paid annually at the end of each year. Since the companies in my comparable group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these firms. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Appendix 2. For the reasons cited there, I employed the quarterly DCF model throughout my calculations, even though the results of the quarterly DCF model for my companies are approximately equal to the results of a properly applied annual DCF model.

Q. PLEASE DESCRIBE THE QUARTERLY DCF MODEL YOU USE.

A. The quarterly DCF model I use is described on Schedule 1 and in Appendix 2. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. HOW DO YOU ESTIMATE THE QUARTERLY DIVIDEND PAYMENTS IN YOUR QUARTERLY DCF MODEL?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by the factor, *(1 + the growth rate, g)*.

Q. CAN YOU ILLUSTRATE HOW YOU ESTIMATE THE NEXT FOUR QUARTERLY DIVIDENDS WITH DATA FOR A SPECIFIC COMPANY?

A. Yes. In the case of American Electric Power, the first company shown in Schedule 1, the last four quarterly dividends are each equal to .41. Thus dividends d_1, d_2, d_3 and d_4 are equal to 0.427 [.41 x (1 + .0416) = .427]. (As noted previously, the logic underlying this procedure is described in Appendix 2.)

Q. HOW DO YOU ESTIMATE THE GROWTH COMPONENT OF THE QUARTERLY DCF MODEL?

A. I use the analysts' estimates of future earnings per share ("EPS") growth reported by I/B/E/S Thomson Reuters.

Q. WHAT ARE THE ANALYSTS' ESTIMATES OF FUTURE EPS GROWTH?

A. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent three- to five-year forecasts of EPS growth.

Q. WHAT IS I/B/E/S?

A. I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as an estimate of future firm performance.

Q. WHY DO YOU USE THE I/B/E/S GROWTH ESTIMATES?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. WHY DO YOU RELY ON ANALYSTS' PROJECTIONS OF FUTURE EPS GROWTH IN ESTIMATING THE INVESTORS' EXPECTED GROWTH RATE RATHER THAN LOOKING AT PAST HISTORICAL GROWTH RATES?

A. I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth.

Q. **HAVE YOU PERFORMED ANY STUDIES CONCERNING THE USE OF ANALYSTS' FORECASTS AS AN ESTIMATE OF INVESTORS' EXPECTED GROWTH RATE, G?**

A. Yes, I prepared a study in conjunction with Willard T. Carleton, Professor of Finance Emeritus at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in the Spring 1988 edition of *The Journal of Portfolio Management.*

Q. **PLEASE SUMMARIZE THE RESULTS OF YOUR STUDY.**

A. First, we performed a correlation analysis to identify the historically oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

Q. HAS YOUR STUDY BEEN UPDATED TO INCLUDE MORE RECENT DATA?

A. Yes. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

Q. WHAT PRICE DO YOU USE IN YOUR DCF MODEL?

A. I use a simple average of the monthly high and low stock prices for each firm for the three-month period ending February 2009. These high and low stock prices were obtained from Thomson Reuters.

Q. WHY DO YOU USE THE THREE-MONTH AVERAGE STOCK PRICE IN APPLYING THE DCF METHOD?

A. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

Q. DO YOU INCLUDE AN ALLOWANCE FOR FLOTATION COSTS IN YOUR DCF ANALYSIS?

A. Yes. I include a 5 percent allowance for flotation costs in my DCF calculations. A complete explanation of the need for flotation costs is contained in Appendix 3.

Q. PLEASE EXPLAIN YOUR INCLUSION OF FLOTATION COSTS.

A. All firms that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, printing expense, etc. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three and five percent of the proceeds from the issue [see Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline due to market pressure has been estimated at two to three percent [see Richard H. Pettway, "The Effects of New Equity Sales upon Utility Share Prices," *Public Utilities Fortnightly,* May 10, 1984, 35—39]. Thus, the total flotation cost, including both issuance expense and market pressure, could range anywhere from five to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in this proceeding.

Q. IS A FLOTATION COST ADJUSTMENT ONLY APPROPRIATE IF A COMPANY ISSUES STOCK DURING THE LAST YEAR?

A. As described in Appendix 3, a flotation cost adjustment is required whether or not a company issued new stock during the last year. Previously incurred flotation costs have not been recovered in previous rate cases; rather, they are a permanent cost associated with past issues of common stock. Just as an adjustment is made to the embedded cost of debt to reflect previously incurred debt issuance costs (regardless of whether additional bond issuances were made in the test year), so should an adjustment be made to the cost of equity regardless of whether additional stock was issued during the last year.

Q. DOES AN ALLOWANCE FOR RECOVERY OF FLOTATION COSTS ASSOCIATED WITH STOCK SALES IN PRIOR YEARS CONSTITUTE RETROACTIVE RATE-MAKING?

A. No. An adjustment for flotation costs on equity is not meant to recover any cost that is properly assigned to prior years. In fact, the adjustment allows a company to recover only the current carrying costs associated with flotation expenses incurred at the time stock sales were made. The original flotation costs themselves will never be recovered, because the stock is assumed to have an infinite life.

Q. WHY SHOULD DUKE ENERGY CAROLINAS BE ALLOWED TO RECOVER FLOTATION EXPENSES IF NO ISSUANCE OF COMMON STOCK OCCURRED DURING THE TEST YEAR?

A. As described in Appendix 3, a flotation cost adjustment is required whether or not a company issued new stock during the test year. Previously incurred flotation costs have not been expensed in previous rate cases; rather, they are a permanent cost associated with past issues of common stock. Just as an adjustment is made to the embedded cost of debt to reflect previously incurred debt issuance costs (regardless of whether additional bond issuances were made in the test year), so should an adjustment be made to the cost of equity regardless of whether additional stock was issued during the test year.

Q. HOW DO YOU APPLY THE DCF APPROACH TO OBTAIN THE COST OF EQUITY CAPITAL FOR DUKE ENERGY CAROLINAS?

A. I apply the DCF approach to the Value Line electric companies shown in Schedule 1.

Q. HOW DO YOU SELECT YOUR COMPARABLE GROUP OF ELECTRIC COMPANIES?

A. I select all the companies in Value Line's groups of electric companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) had at least three analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) are not the subject of a merger offer that has not been completed.

Q. WHY DO YOU ELIMINATE COMPANIES THAT HAVE EITHER DECREASED OR ELIMINATED THEIR DIVIDEND IN THE PAST TWO YEARS?

A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, an assumption that the company's dividend will grow at the same rate into the indefinite future is questionable.

Q. WHY DO YOU ELIMINATE COMPANIES THAT HAVE FEWER THAN THREE ANALYSTS INCLUDED IN THE I/B/E/S MEAN FORECASTS?

A. The DCF model also requires a reliable estimate of a company's expected future growth. For most companies, the I/B/E/S mean growth forecast is the best available estimate of the growth term in the DCF model. However, the I/B/E/S estimate may be less reliable if the mean estimate is based on the inputs of very few analysts. On the basis of my professional judgment, I believe that at least three analysts' estimates are a reasonable minimum number.

Q. WHY DO YOU ELIMINATE COMPANIES THAT ARE THE SUBJECT OF A MERGER OFFER THAT HAS NOT BEEN COMPLETED?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR APPLICATION OF THE DCF MODEL TO YOUR COMPARABLE COMPANY GROUP.

A. As shown on Schedule 1, I obtain a DCF result of 12.4 percent for my comparable company group.

D. RISK PREMIUM METHOD

Q. PLEASE DESCRIBE THE RISK PREMIUM METHOD OF ESTIMATING DUKE ENERGY CAROLINAS' COST OF EQUITY.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment in Duke Energy Carolinas that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. DOES THE RISK PREMIUM APPROACH SPECIFY WHAT DEBT INSTRUMENT SHOULD BE USED TO ESTIMATE THE INTEREST RATE COMPONENT IN THE METHODOLOGY?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks and the returns on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. DOES THE RISK PREMIUM APPROACH REQUIRE THAT THE SAME COMPANIES BE USED TO ESTIMATE THE STOCK RETURN AS ARE USED TO ESTIMATE THE BOND RETURN?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the return on Treasury securities such as long-term Treasury bonds. Clearly, in this widely-accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, since the U.S. government is not a company.

Q. HOW DO YOU MEASURE THE REQUIRED RISK PREMIUM ON AN EQUITY INVESTMENT IN DUKE ENERGY CAROLINAS?

A. I use two methods to estimate the required risk premium on an equity investment in Duke Energy Carolinas. The first is called the ex ante risk premium method and the second is called the ex post risk premium method.

1. Ex Ante Risk Premium Method

Q. PLEASE DESCRIBE YOUR EX ANTE RISK PREMIUM APPROACH FOR MEASURING THE REQUIRED RISK PREMIUM ON AN EQUITY INVESTMENT IN DUKE ENERGY CAROLINAS.

A. My ex ante risk premium method is based on studies of the DCF expected return on a comparable group of electric companies compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculated the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY}	=	the required risk premium on an equity investment in the proxy group of companies,
DCF_{PROXY}	=	average DCF estimated cost of equity on a portfolio of proxy companies; and
I_A	=	the yield to maturity on an investment in A-rated utility bonds.

I then perform a regression analysis to determine if there was a relationship between the calculated risk premium and interest rates. Finally, I use the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity, I then add the required risk premium to the forecasted interest rate on A-rated utility bonds. A detailed description of my ex ante risk premium studies is contained in Appendix 3, and the underlying DCF results and interest rates are displayed in Schedule 2.

Q. WHAT COST OF EQUITY DO YOU OBTAIN FROM YOUR EX ANTE RISK PREMIUM METHOD?

A. To estimate the cost of equity using the ex ante risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the forecasted yield to maturity on A-rated utility bonds.[3] The forecasted yield to maturity on A-rated utility bonds, 6.32 percent, is obtained by adding the February spread between A-rated and AA-rated utility bonds to the Global Insight forecast of the yield to maturity on AA-rated bonds for 2010. My analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 5.06 percent. Adding an estimated risk premium of 5.06 percent to the 6.32 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 11.4 percent using the ex ante risk premium method.

2. Ex Post Risk Premium Method

Q. PLEASE DESCRIBE YOUR EX POST RISK PREMIUM METHOD FOR MEASURING THE REQUIRED RISK PREMIUM ON AN EQUITY INVESTMENT IN DUKE ENERGY CAROLINAS.

A. I first perform a study of the comparable returns received by bond and stock investors over the 71 years of my study. I estimate the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond

[3] As noted above, one could use the yield to maturity on other debt investments to measure the interest rate component of the risk premium approach as long as one uses the yield on the same debt investment to measure the expected risk premium component of the risk premium approach. I chose to use the yield on A-rated utility bonds because it is a frequently-used benchmark for utility bond yields.

yield data on Moody's A-rated Utility Bonds. My study consists of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2009. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year between 1937 and 2009 are shown on Schedule 3. The average annual return on an investment in the S&P 500 stock portfolio is 10.8 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio was 6.3 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 4.5 percent.

I also conduct a second study using stock data on the S&P Utilities rather than the S&P 500. As shown on Schedule 4, the S&P Utility stock portfolio showed an average annual return of 10.5 percent per year. Thus, the return on the S&P Utility stock portfolio exceeded the return on the Moody's A–rated utility bond portfolio by 4.2 percent.

Q. WHY IS IT APPROPRIATE TO PERFORM YOUR EX POST RISK PREMIUM ANALYSIS USING BOTH THE S&P 500 AND THE S&P UTILITIES STOCK INDICES?

A. I perform my ex post risk premium analysis on both the S&P 500 and the S&P Utilities because I believe electric energy companies today face risks that are somewhere in between the average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2009. Thus, I use the average of the two historically-based risk premiums as my estimate of the required risk premium for Duke Energy Carolinas in my ex post risk premium method.

Q. WHY DO YOU ANALYZE INVESTORS' EXPERIENCES OVER SUCH A LONG TIME FRAME?

A. Because day-to-day stock price movements can be somewhat random, it is inappropriate to rely on short-run movements in stock prices in order to derive a reliable risk premium. Rather than buying and selling frequently in anticipation of highly volatile price movements, most investors employ a strategy of buying and holding a diversified portfolio of stocks. This buy-and-hold strategy will allow an investor to achieve a much more predictable long-run return on stock investments and at the same time will minimize transaction costs. The situation is very similar to the problem of predicting the results of coin tosses. I cannot predict with any reasonable degree of accuracy the result of a single, or even a few, flips of a balanced coin; but I can predict with a good deal of confidence that approximately 50 heads will appear in 100 tosses of this coin. Under these circumstances, it is most appropriate to estimate future experience from long-run evidence of investment performance.

Q. WOULD YOUR STUDY PROVIDE A DIFFERENT RISK PREMIUM IF YOU STARTED WITH A DIFFERENT TIME PERIOD?

A. Yes. The risk premium results do vary somewhat depending on the historical time period chosen. My policy was to go back as far in history as I could get reliable data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935. This Act significantly changed the structure of the public utility industry. Since the Public Utility Holding Company Act of 1935 was not implemented until the beginning of 1937, I felt that numbers taken from before this date would not be comparable to those taken after. (The repeal of the 1935 Act has not materially impacted the structure of the public utility industry; thus, the Act's repeal does not have any impact on my choice of time period.)

Q. WHY IS IT NECESSARY TO EXAMINE THE YIELD FROM DEBT INVESTMENTS IN ORDER TO DETERMINE THE INVESTORS' REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields. This is because the return on equity, being a residual return, is less certain than the yield on bonds and investors must be compensated for this uncertainty. Second, the investors' current expectations concerning the amount by which the return on equity will exceed the bond yield will be strongly influenced by historical differences in returns to bond and stock investors. For these reasons, we can estimate investors' current expected returns from an equity investment from knowledge of current bond yields and past differences between returns on stocks and bonds.

Q. IS THERE ANY SIGNIFICANT TREND IN THE EQUITY RISK PREMIUM OVER THE 1937 TO 2009 TIME PERIOD OF YOUR RISK PREMIUM STUDY?

A. No. Statisticians test for trends in data series by regressing the data observations against time. I perform such a time series regression on my two data sets of historical risk premiums. As shown below, there is no statistically significant trend in my risk premium data. Indeed, the coefficient on the time variable is insignificantly different from zero (if there were a trend, the coefficient on the time variable should be significantly different from zero).

TABLE 2
REGRESSION OUTPUT FOR RISK PREMIUM ON S&P 500

Line No.		Intercept	Time	Adjusted R Square	F
1	Coefficient	1.383	(0.001)	(0.006)	0.56
2	T Statistic	0.776	(0.751)		

TABLE 3
REGRESSION OUTPUT FOR RISK PREMIUM ON S&P UTILITIES

Line No.		Intercept	Time	Adjusted R Square	F
1	Coefficient	1.654	(0.001)	(0.001)	0.91
2	T Statistic	0.980	(0.955)		

Q. DO YOU HAVE ANY OTHER EVIDENCE THAT THERE HAS BEEN NO SIGNIFICANT TREND IN RISK PREMIUM RESULTS OVER TIME?

A. Yes. The *Stocks, Bonds, Bills, and Inflation® 2009 Valuation Edition Yearbook* ("SBBI") published by Morningstar, Inc., (Morningstar has purchased the publication formerly published by Ibbotson Associates) contains an analysis of "trends" in historical risk premium data. SBBI uses correlation analysis to determine if there is any pattern or "trend" in risk premiums over time. This analysis also demonstrates that there are no trends in risk premiums over time.

Q. WHAT IS THE SIGNIFICANCE OF THE EVIDENCE THAT HISTORICAL RISK PREMIUMS HAVE NO TREND OR OTHER STATISTICAL PATTERN OVER TIME?

A. The significance of this evidence is that the average historical risk premium is a reasonable estimate of the future expected risk premium. As noted in SBBI:

> The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year. That is, there is no discernable pattern in the realized equity risk premium—it is virtually impossible to forecast next year's realized risk premium based on the premium of the previous year. For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is as likely to be higher as it is lower. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values. [*SBBI*, page 61.]

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR EX POST RISK PREMIUM ANALYSES ABOUT THE REQUIRED RETURN ON AN EQUITY INVESTMENT IN DUKE ENERGY CAROLINAS?

A. My studies provide strong evidence that investors today require an equity return of approximately 4.2 to 4.5 percentage points above the expected yield on A-rated utility bonds. The forecast yield on A-rated utility bonds at 2010 is 6.32 percent. Adding a 4.2 to 4.5 percentage point risk premium to a yield of 6.3 percent on A-rated utility bonds, I obtain an expected return on equity in the range 10.5 percent to 10.8 percent, with a midpoint of 10.6 percent. Adding a 27 basis-point allowance for flotation costs,[4] I obtain an estimate of 10.9 percent as the ex post risk premium cost of equity for Duke Energy Carolinas.

E. CAPITAL ASSET PRICING MODEL

Q. WHAT IS THE CAPM?

A. The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

[4] I determine the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q. HOW DO YOU USE THE CAPM TO ESTIMATE THE COST OF EQUITY FOR YOUR COMPARABLE COMPANIES?

A. The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use the forecasted yield to maturity on 20-year Treasury bonds[5] of 4.80 percent, using data from Bloomberg.[6] For my estimate of the company-specific risk, or beta, I use the average 0.73 Value Line beta for my comparable electric companies. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio using historical risk premium data reported by SBBI. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

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[5] I use the 20-year Treasury bond to estimate the risk-free rate because SBBI estimates the risk premium using 20-year Treasury bonds and the analyst should use the same maturity to estimate the risk-free rate as is used to estimate the risk premium on the market portfolio.

[6] Bloomberg provides a forecasted yield for 30-year Treasury bonds rather than for the 20-year Treasury bond. To obtain a forecasted yield for the 20-year Treasury bond, I compare the current average yield at February 2009 for the 20-year Treasury bond, 3.83 percent, to the average yield for the 10-year Treasury bond, 2.87 percent. I add the difference between the current yields on the 30-year and 20-year Treasury bonds, 96 basis points, to Bloomberg's average forecasted yield for 10-year Treasury bonds in 2010, 3.84 percent, to obtain a forecasted yield of 4.80 percent for the 20-year Treasury bond.

1. Historical CAPM

Q. HOW DO YOU ESTIMATE THE EXPECTED RISK PREMIUM ON THE MARKET PORTFOLIO USING HISTORICAL RISK PREMIUM DATA REPORTED BY SBBI?

A. I estimate the expected risk premium on the market portfolio by calculating the difference between the arithmetic mean return on the S&P 500 from 1926 through 2008 (11.7 percent) and the average income return on 20-year U.S. Treasury bonds over the same period (5.2 percent). My historical risk premium method produces a risk premium of 6.5 percent (11.7 – 5.2 = 6.5).[7] As explained in SBBI, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future:

Q. WHY DO YOU RECOMMEND THAT THE RISK PREMIUM ON THE MARKET PORTFOLIO BE ESTIMATED USING THE ARITHMETIC MEAN RETURN ON THE S&P 500?

A. As explained in SBBI, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return. [SBBI, p. 77.]

[7] *See* 2009 Ibbotson® Risk Premia Over Time Report, Estimates for 1926 – 2008, p. 4, published by Morningstar.®

A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Schedule 5.

Q. WHY DO YOU RECOMMEND THAT THE RISK PREMIUM ON THE MARKET PORTFOLIO BE MEASURED USING THE INCOME RETURN ON 20-YEAR TREASURY BONDS RATHER THAN THE TOTAL RETURN ON THESE BONDS?

A. As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q. WHAT CAPM RESULT DO YOU OBTAIN WHEN YOU ESTIMATE THE EXPECTED RISK PREMIUM ON THE MARKET PORTFOLIO FROM THE ARITHMETIC MEAN DIFFERENCE BETWEEN THE RETURN ON THE MARKET AND THE YIELD ON 20-YEAR TREASURY BONDS?

A. Using a risk-free rate equal to 4.8 percent, a beta equal to 0.73, and a risk premium on the market portfolio equal to 6.5 percent, I obtain an historical CAPM estimate cost of equity equal to 9.8 percent (4.8 + 0.73 x 6.5 = 9.8, see Schedule 6).

Q. DO YOU BELIEVE THAT 9.8 PERCENT IS A REASONABLE ESTIMATE OF THE COST OF EQUITY FOR DUKE ENERGY CAROLINAS IN TODAY'S TURBULENT ECONOMIC ENVIRONMENT?

A. No. As noted above, the U.S. economy is in the midst of the largest housing, employment, credit, and financial crisis since World War II. As a result of this crisis, investors have increased their aversion to risk, reduced their leverage, increased their demand for liquidity, and increased their required rates of return on risky investments. Contrary to the evidence that investors have increased their required rates of return on risky investments, the indicated cost of equity from applying the historical CAPM has declined significantly over the last several months.

Q. WHY DOES THE CAPM PRODUCE SUCH A LOW ESTIMATE OF THE COST OF EQUITY IN TODAY'S TURBULENT ECONOMIC ENVIRONMENT?

A. The CAPM method requires estimates of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. The cost of equity estimate from applying the historical CAPM has declined because all of the components have declined significantly: (1) the risk-free rate, measured by the U.S. Treasury bond yield, has declined significantly because of the federal government's efforts to boost the economy and investors' desires to reduce their exposure to risk; (2) betas measured from five years of historical data have declined and thus do not reflect the current risk environment; and (3) the historical market risk premium has declined as a result of the virtually unprecedented magnitude of losses in stock market returns over the past year.

Q. YOU NOTE THAT THE RISK-FREE RATE, MEASURED BY THE YIELD ON U.S. TREASURY SECURITIES, HAS DECLINED IN RECENT MONTHS. HAVE OTHER CORPORATE INTEREST RATES ALSO

DECLINED AS A RESULT OF THE TURBULENCE IN THE FINANCIAL MARKETS?

A. No. As a result of investors increased aversion to risk, interest rates on corporate bonds have generally increased. As shown below, the spreads on both investment-grade and speculative bonds over Treasury rates is now at the highest level in many years.

Table 4
Standard & Poor's U.S. Composite Credit Spreads[8]

(BASIS POINTS)	3-11-09	BEGINNING OF 2008	FIVE-YEAR MOVING AVERAGE
S&P investment-grade composite credit spreads	488	204	181
S&P speculative-grade composite credit spreads	1,475	576	514

Q. **WHAT CONCLUSIONS DO YOU DRAW FROM YOUR OBSERVATION THAT INTEREST RATES ON U.S. TREASURY SECURITIES HAVE DECLINED IN RECENT MONTHS, WHILE INTEREST RATES ON CORPORATE BONDS HAVE GENERALLY INCREASED?**

A. I conclude that rates on U.S. Treasury securities are artificially low at present because of the Federal Reserve's massive efforts to encourage renewed investment in the economy. Thus, the cost of equity results produced by the CAPM are, for this reason alone, not indicative of capital costs for public utilities such as Duke Energy Carolinas.

Q. **IS THERE ANY EVIDENCE FROM THE FINANCE LITERATURE THAT A REASONABLE APPLICATION OF THE HISTORICAL CAPM**

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8 Standard & Poor's RatingsDirect, March 12, 2009.

MAY PRODUCE HIGHER COST OF EQUITY RESULTS THAN YOU HAVE JUST REPORTED?

A. Yes. There is substantial evidence that the historical CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and to overestimate the cost of equity for companies whose equity beta is greater than 1.0.

Q. WHAT IS THE EVIDENCE THAT THE CAPM TENDS TO UNDERESTIMATE THE COST OF EQUITY FOR COMPANIES WITH BETAS LESS THAN 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and to overestimate the cost of equity for companies whose equity beta is greater than 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy, Banz, Fama and French (1992), Fama and French (2004) and Fama and MacBeth.[9]

Q. CAN YOU BRIEFLY SUMMARIZE THESE ARTICLES?

A. Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation

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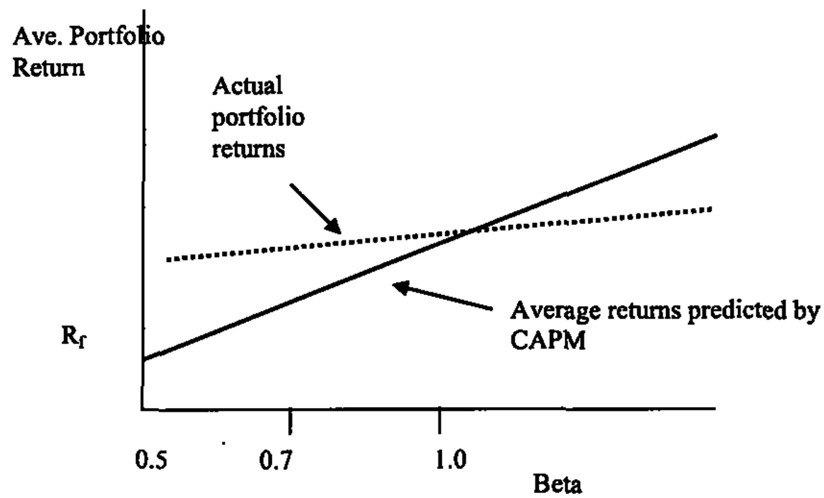
[9] Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives* (Summer 2004), 18:3, pp. 25 – 46.

$$ER_i = R_f + \beta_i \left[ER_m - R_f\right],$$

where ER_i is the expected return on security or portfolio i, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and βi is a measure of the risk of investing in security or portfolio i (see Figure 2 below).

Figure 2
Average Returns Compared to Beta
for Portfolios Formed on Prior Beta



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that the relationship between returns and betas is inconsistent with the relationship posited by the CAPM. As described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 2 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 2 than the straight line, they generally agree that the dotted line lies above the straight line for portfolios with betas less than 1.0 and below the straight line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0, and overestimates portfolio returns for portfolios with betas greater than 1.0.

Q. DO YOU HAVE ANY EVIDENCE THAT THE CAPM TENDS TO UNDERESTIMATE THE COST OF EQUITY FOR UTILITY COMPANIES WITH AVERAGE BETAS LESS THAN 1.0?

A. Yes. As shown in Schedule 7, over the period 1937 through 2008, investors in the S&P Utilities have earned a risk premium over the yield on long-term Treasury bonds equal to 5.03 percent, while investors in the S&P 500 have earned a risk premium over the yield on long-term Treasury bonds equal to 5.30 percent. According to the CAPM, investors in utilities stocks should expect to earn a risk premium over the yield on long-term Treasury securities equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the risk premium on the utility portfolio to the risk premium on the S&P 500 should equal the utility beta. However, the average utility beta is currently approximately 0.73, whereas the historical ratio of the utility risk premium to the S&P 500 risk premium is 0.95 (5.03/5.30 = 0.95). In short, an application of the historical CAPM at this time is significantly underestimating the cost of equity for utility companies with an average beta less than 1.0.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR OBSERVATION THAT RISK-FREE RATES ARE ARTIFICIALLY LOW AND THE WIDESPREAD EVIDENCE THAT THE CAPM TENDS TO UNDERESTIMATE THE COST OF EQUITY FOR COMPANIES WITH BETAS LESS THAN 1.0?

A. I note above that my observation that Treasury yields are artificially low is evidence that CAPM cost of equity results not indicative of the true cost for public utilities such as Duke Energy Carolinas. The further observation that the average utility beta is significantly less than 1.0 at this time, and that the historical CAPM underestimates the cost of equity for companies with betas significantly less than 1.0, causes me to conclude that the cost of equity results from applying the CAPM should be given less weight than the cost of equity results from my other cost of equity methodologies. However, to be conservative, I continue to consider my CAPM results in my overall cost of equity recommendation.

2. DCF-Based CAPM

Q. HOW DOES YOUR DCF-BASED CAPM DIFFER FROM YOUR HISTORICAL CAPM?

A. As noted above, my DCF-based CAPM differs from my historical CAPM only in the method I use to estimate the risk premium on the market portfolio. In the historical CAPM, I use historical risk premium data to estimate the risk premium on the market portfolio. In the DCF-based CAPM, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. WHAT RISK PREMIUM DO YOU OBTAIN WHEN YOU CALCULATE THE DIFFERENCE BETWEEN THE DCF-RETURN ON THE S&P 500 AND THE RISK-FREE RATE?

A. Using this method, I obtain a risk premium on the market portfolio equal to 8.6 percent (see Schedule 8).

Q. WHAT CAPM RESULT DO YOU OBTAIN WHEN YOU ESTIMATE THE EXPECTED RETURN ON THE MARKET PORTFOLIO BY APPLYING THE DCF MODEL TO THE S&P 500?

A. Using a risk-free rate of 4.8 percent, a beta of 0.73, and a risk premium on the market portfolio of 8.6 percent, I obtain a CAPM result of 11.1 percent.

Q. RECOGNIZING THAT TREASURY RATES ARE ARTIFICIALLY LOW AT PRESENT AND THAT THE CAPM SIGNIFICANTLY UNDERESTIMATES THE COST OF EQUITY FOR COMPANIES WITH BETAS LESS THAN 1.0, HOW DO YOU RECOMMEND THAT THE COMMISSION CONSIDER YOUR CAPM COST OF EQUITY RESULTS IN THIS PROCEEDING?

A. Given that Treasury rates are artificially low and that the CAPM significantly underestimates the cost of equity for companies with betas less than 1.0, I recommend that the Commission give less weight to the cost of equity results obtained from my CAPM analyses.

V. FAIR RATE OF RETURN ON EQUITY

Q. BASED ON YOUR APPLICATION OF SEVERAL COST OF EQUITY METHODS TO YOUR COMPARABLE COMPANIES, WHAT IS YOUR CONCLUSION REGARDING YOUR COMPARABLE COMPANIES' COST OF EQUITY?

A. Based on my application of several cost of equity methods to my comparable companies, I conclude that my comparable companies' cost of equity is 11.1 percent. As shown in table below, 11.1 percent is the simple average of my

DCF, ex ante risk premium, ex post risk premium, historical CAPM, and DCF-based CAPM results.

TABLE 5
COST OF EQUITY MODEL RESULTS

METHOD	COST OF EQUITY
Discounted Cash Flow	12.4%
Ex Ante Risk Premium	11.4%
Ex Post Risk Premium	10.9%
Historical CAPM	9.8%
DCF-Based CAPM	11.1%
Average	11.1%

Q. DOES YOUR 11.1 PERCENT COST OF EQUITY CONCLUSION FOR YOUR COMPARABLE GROUPS DEPEND ON THE PERCENTAGES OF DEBT AND EQUITY IN YOUR COMPARABLE COMPANIES' AVERAGE CAPITAL STRUCTURE?

A. Yes. The 11.1 percent cost of equity for my comparable groups reflects the financial risk associated with my comparable companies' average capital structures, where the capital structure weights are measured in terms of market values.[10] Since financial leverage, that is, the use of debt financing, increases the risk of investing in the comparable companies' equity, the cost of equity would be higher for a capital structure containing more leverage.

Q. WHAT ARE THE AVERAGE PERCENTAGES OF DEBT AND EQUITY IN YOUR COMPARABLE COMPANIES' CAPITAL STRUCTURES?

[10] See Section II above for a discussion of why investors use market value capital structure weights to assess a company's financial risk.

A. As shown in Schedule 9, my electric company group has an average capital structure containing 37.54 percent debt, 0.72 percent preferred stock, and 61.74 percent common equity.

Q. HOW DOES DUKE ENERGY CAROLINAS' RATE MAKING CAPITAL STRUCTURE FOR THE PURPOSE OF RATE SETTING IN THIS PROCEEDING COMPARE TO THE AVERAGE CAPITAL STRUCTURE OF YOUR COMPARABLE COMPANIES?

A. Duke Energy Carolinas' rate making capital structure contains 47.0 percent long-term debt and 53.0 percent common equity. Although this capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for ratemaking purposes, from an investor's viewpoint, Duke Energy Carolinas' ratemaking capital structure embodies greater financial risk than is reflected in my cost of equity estimates from my comparable companies.

Q. YOU NOTE EARLIER THAT THE COST OF EQUITY DEPENDS ON A COMPANY'S CAPITAL STRUCTURE. IS THERE ANY WAY TO ADJUST THE 11.1 PERCENT COST OF EQUITY FOR YOUR COMPARABLE COMPANIES TO REFLECT THE HIGHER FINANCIAL RISK EMBODIED IN DUKE ENERGY CAROLINAS' RATE MAKING CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Yes. Since my comparable groups are comparable in risk to Duke Energy Carolinas, Duke Energy Carolinas should have the same weighted average cost of capital as my comparable companies. It is a simple matter to determine what cost of equity Duke Energy Carolinas should have in order to have the same weighted average cost of capital as my comparable companies.

Q. HAVE YOU PERFORMED SUCH A CALCULATION?

A. Yes. I adjusted the 11.1 percent average cost of equity for my comparable groups by recognizing that to attract capital, Duke Energy Carolinas must have the same weighted average cost of capital as my comparable group. As shown in Schedule 10, my analysis indicates that Duke Energy Carolinas would require a fair rate of return on equity equal to 12.3 percent in order to have the same weighted average cost of capital as my comparable companies.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

LIST OF ATTACHMENTS

SCHEDULE 1
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR ELECTRIC ENERGY COMPANIES

LINE NO.	COMPANY	D_0	P_0	GROWTH	COST OF EQUITY
1	Amer. Elec. Power	0.410	31.363	4.16%	10.1%
2	Avista Corp.	0.180	17.990	4.67%	9.1%
4	Dominion Resources	0.438	34.423	8.16%	13.8%
5	DPL Inc.	0.275	21.508	10.33%	16.6%
6	Duke Energy	0.230	14.863	4.46%	11.5%
7	Consol. Edison	0.585	39.205	2.61%	9.3%
8	Entergy Corp.	0.750	77.203	9.42%	14.1%
9	Exelon Corp.	0.525	53.210	8.47%	13.1%
10	FirstEnergy Corp.	0.550	49.527	9.00%	14.4%
11	FPL Group	0.473	48.890	9.62%	14.1%
13	NSTAR	0.375	34.283	6.00%	10.8%
14	Northeast Utilities	0.238	23.365	8.15%	12.5%
15	PG&E Corp.	0.390	37.313	6.84%	11.7%
16	Progress Energy	0.620	38.453	5.56%	13.0%
17	Pinnacle West Capital	0.525	31.242	4.33%	12.0%
18	Pepco Holdings	0.270	17.060	4.67%	12.0%
19	Portland General	0.245	18.268	5.44%	11.6%
21	SCANA Corp.	0.460	34.060	4.52%	10.7%
22	Southern Co.	0.420	34.428	5.36%	11.0%
23	Sempra Energy	0.350	42.948	7.20%	10.9%
25	Vectren Corp.	0.335	24.848	7.20%	13.4%
26	Wisconsin Energy	0.338	42.678	9.13%	12.3%
27	Westar Energy	0.290	19.268	3.84%	10.7%
28	Xcel Energy Inc.	0.238	18.153	6.72%	12.8%
29	Market-Weighted Average.				12.4%

Notes:

d_0	=	Most recent quarterly dividend.
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per Value Line by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending February 2009 per Thomson Reuters.
FC	=	Flotation cost allowance (5%) as a percent of stock price.
g	=	I/B/E/S forecast of future earnings growth February 2009 from Thomson Reuters.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

SCHEDULE 2
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC ENERGY COMPANIES TO THE INTEREST RATE ON MOODY'S A-RATED UTILITY BONDS

Line No.	Date	DCF	Bond Yield	Risk Premium
1	Sep-99	0.1169	0.0793	0.0376
2	Oct-99	0.1177	0.0806	0.0371
3	Nov-99	0.1208	0.0794	0.0414
4	Dec-99	0.1258	0.0814	0.0444
5	Jan-00	0.1250	0.0835	0.0415
6	Feb-00	0.1295	0.0825	0.0470
7	Mar-00	0.1336	0.0828	0.0508
8	Apr-00	0.1257	0.0829	0.0428
9	May-00	0.1242	0.0870	0.0372
10	Jun-00	0.1266	0.0836	0.0430
11	Jul-00	0.1276	0.0825	0.0451
12	Aug-00	0.1247	0.0813	0.0434
13	Sep-00	0.1180	0.0823	0.0357
14	Oct-00	0.1182	0.0814	0.0368
15	Nov-00	0.1187	0.0811	0.0376
16	Dec-00	0.1169	0.0784	0.0385
17	Jan-01	0.1205	0.0780	0.0425
18	Feb-01	0.1210	0.0774	0.0436
19	Mar-01	0.1215	0.0768	0.0447
20	Apr-01	0.1277	0.0794	0.0483
21	May-01	0.1304	0.0799	0.0505
22	Jun-01	0.1309	0.0785	0.0524
23	Jul-01	0.1324	0.0778	0.0546
24	Aug-01	0.1330	0.0759	0.0571
25	Sep-01	0.1356	0.0775	0.0581
26	Oct-01	0.1334	0.0763	0.0571
27	Nov-01	0.1338	0.0757	0.0581
28	Dec-01	0.1335	0.0783	0.0552
29	Jan-02	0.1314	0.0766	0.0548
30	Feb-02	0.1327	0.0754	0.0573
31	Mar-02	0.1286	0.0776	0.0510
32	Apr-02	0.1250	0.0757	0.0493
33	May-02	0.1258	0.0752	0.0506
34	Jun-02	0.1257	0.0741	0.0516
35	Jul-02	0.1322	0.0731	0.0591
36	Aug-02	0.1269	0.0717	0.0552
37	Sep-02	0.1288	0.0708	0.0580
38	Oct-02	0.1292	0.0723	0.0569
39	Nov-02	0.1238	0.0714	0.0524
40	Dec-02	0.1208	0.0707	0.0501
41	Jan-03	0.1172	0.0706	0.0466
42	Feb-03	0.1210	0.0693	0.0517
43	Mar-03	0.1171	0.0679	0.0492
44	Apr-03	0.1131	0.0664	0.0467
45	May-03	0.1072	0.0636	0.0436
46	Jun-03	0.1027	0.0621	0.0406
47	Jul-03	0.1034	0.0657	0.0377
48	Aug-03	0.1035	0.0678	0.0357

Line No.	Date	DCF	Bond Yield	Risk Premium
49	Sep-03	0.1006	0.0656	0.0350
50	Oct-03	0.0989	0.0643	0.0346
51	Nov-03	0.0978	0.0637	0.0341
52	Dec-03	0.0949	0.0627	0.0322
53	Jan-04	0.0923	0.0615	0.0308
54	Feb-04	0.0919	0.0615	0.0304
55	Mar-04	0.0916	0.0597	0.0319
56	Apr-04	0.0927	0.0635	0.0292
57	May-04	0.0966	0.0662	0.0304
58	Jun-04	0.0967	0.0646	0.0321
59	Jul-04	0.0959	0.0627	0.0332
60	Aug-04	0.0964	0.0614	0.0350
61	Sep-04	0.0956	0.0598	0.0358
62	Oct-04	0.0953	0.0594	0.0359
63	Nov-04	0.0911	0.0597	0.0314
64	Dec-04	0.0931	0.0592	0.0339
65	Jan-05	0.0933	0.0578	0.0355
66	Feb-05	0.0930	0.0561	0.0369
67	Mar-05	0.0925	0.0583	0.0342
68	Apr-05	0.0927	0.0564	0.0363
69	May-05	0.0922	0.0553	0.0368
70	Jun-05	0.0927	0.0540	0.0387
71	Jul-05	0.0913	0.0551	0.0362
72	Aug-05	0.0923	0.0550	0.0373
73	Sep-05	0.0950	0.0552	0.0398
74	Oct-05	0.0962	0.0579	0.0383
75	Nov-05	0.1005	0.0588	0.0417
76	Dec-05	0.1012	0.0580	0.0432
77	Jan-06	0.1015	0.0575	0.0440
78	Feb-06	0.1126	0.0582	0.0544
79	Mar-06	0.1111	0.0598	0.0513
80	Apr-06	0.1122	0.0629	0.0493
81	May-06	0.1118	0.0642	0.0476
82	Jun-06	0.1157	0.0640	0.0517
83	Jul-06	0.1151	0.0637	0.0514
84	Aug-06	0.1138	0.0620	0.0518
85	Sep-06	0.1164	0.0600	0.0564
86	Oct-06	0.1154	0.0598	0.0556
87	Nov-06	0.1158	0.0580	0.0578
88	Dec-06	0.1145	0.0581	0.0564
89	Jan-07	0.1136	0.0596	0.0540
90	Feb-07	0.1110	0.0590	0.0520
91	Mar-07	0.1120	0.0585	0.0535
92	Apr-07	0.1074	0.0597	0.0477
93	May-07	0.1108	0.0599	0.0509
94	Jun-07	0.1169	0.0630	0.0539
95	Jul-07	0.1179	0.0625	0.0554
96	Aug-07	0.1169	0.0624	0.0545
97	Sep-07	0.1135	0.0618	0.0517
98	Oct-07	0.1129	0.0611	0.0518
99	Nov-07	0.1108	0.0597	0.0511
100	*Dec-07*	*0.1129*	*0.0616*	*0.0513*
101	Jan-08	0.1229	0.0602	0.0627
102	Feb-08	0.1143	0.0621	0.0522
103	Mar-08	0.1178	0.0620	0.0558
104	Apr-08	0.1137	0.0629	0.0508

Line No.	Date	DCF	Bond Yield	Risk Premium
105	May-08	0.1142	0.0627	0.0515
106	Jun-08	0.1123	0.0638	0.0486
107	Jul-08	0.1172	0.0639	0.0533
108	Aug-08	0.1184	0.0638	0.0546
109	Sep-08	0.1128	0.0646	0.0481
110	Oct-08	0.1219	0.0756	0.0463
111	Nov-08	0.1247	0.0762	0.0485
112	Dec-08	0.1246	0.0658	0.0588
113	Jan-09	0.1225	0.0639	0.0586
114	Feb-09	0.1254	0.0631	0.0623
115	Average	0.1138	0.0675	0.0462

Notes: Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 4 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend per Value Line, Thomson Reuters
P_0	=	Average of the monthly high and low stock prices for each month per Thomson Reuters
FC	=	Flotation cost allowance (5%) as a percentage of stock price
g	=	I/B/E/S forecast of future earnings growth for each month.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1 - FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

SCHEDULE 3
COMPARATIVE RETURNS ON S&P 500 STOCK INDEX
AND MOODY'S A-RATED UTILITY BONDS 1937 - 2009

Line No.	Year	S&P 500 Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return
1	2009	865.58	0.0310		$68.43	
2	2008	1,380.33	0.0211	-35.19%	$72.25	0.24%
3	2007	1,424.16	0.0181	-1.27%	$72.91	4.59%
4	2006	1,278.72	0.0183	13.20%	$75.25	2.20%
5	2005	1,181.41	0.0177	10.01%	$74.91	5.80%
6	2004	1,132.52	0.0162	5.94%	$70.87	11.34%
7	2003	895.84	0.0180	28.22%	$62.26	20.27%
8	2002	1,140.21	0.0138	-20.05%	$57.44	15.35%
9	2001	1,335.63	0.0116	-13.47%	$56.40	8.93%
10	2000	1,425.59	0.0118	-5.13%	$52.60	14.82%
11	1999	1,248.77	0.0130	15.46%	$63.03	-10.20%
12	1998	963.35	0.0162	31.25%	$62.43	7.38%
13	1997	766.22	0.0195	27.68%	$56.62	17.32%
14	1996	614.42	0.0231	27.02%	$60.91	-0.48%
15	1995	465.25	0.0287	34.93%	$50.22	29.26%
16	1994	472.99	0.0269	1.05%	$60.01	-9.65%
17	1993	435.23	0.0288	11.56%	$53.13	20.48%
18	1992	416.08	0.0290	7.50%	$49.56	15.27%
19	1991	325.49	0.0382	31.65%	$44.84	19.44%
20	1990	339.97	0.0341	-0.85%	$45.60	7.11%
21	1989	285.41	0.0364	22.76%	$43.06	15.18%
22	1988	250.48	0.0366	17.61%	$40.10	17.36%
23	1987	264.51	0.0317	-2.13%	$48.92	-9.84%
24	1986	208.19	0.0390	30.95%	$39.98	32.36%
25	1985	171.61	0.0451	25.83%	$32.57	35.05%
26	1984	166.39	0.0427	7.41%	$31.49	16.12%
27	1983	144.27	0.0479	20.12%	$29.41	20.65%
28	1982	117.28	0.0595	28.96%	$24.48	36.48%
29	1981	132.97	0.0480	-7.00%	$29.37	-3.01%
30	1980	110.87	0.0541	25.34%	$34.69	-3.81%
31	1979	99.71	0.0533	16.52%	$43.91	-11.89%
32	1978	90.25	0.0532	15.80%	$49.09	-2.40%
33	1977	103.80	0.0399	-9.06%	$50.95	4.20%
34	1976	96.86	0.0380	10.96%	$43.91	25.13%
35	1975	72.56	0.0507	38.56%	$41.76	14.75%
36	1974	96.11	0.0364	-20.86%	$52.54	-12.91%
37	1973	118.40	0.0269	-16.14%	$58.51	-3.37%
38	1972	103.30	0.0296	17.58%	$56.47	10.69%
39	1971	93.49	0.0332	13.81%	$53.93	12.13%
40	1970	90.31	0.0356	7.08%	$50.46	14.81%
41	1969	102.00	0.0306	-8.40%	$62.43	-12.76%
42	1968	95.04	0.0313	10.45%	$66.97	-0.81%
43	1967	84.45	0.0351	16.05%	$78.69	-9.81%

Line No.	Year	S&P 500 Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return
44	1966	93.32	0.0302	-6.48%	$86.57	-4.48%
45	1965	86.12	0.0299	11.35%	$91.40	-0.91%
46	1964	76.45	0.0305	15.70%	$92.01	3.68%
47	1963	65.06	0.0331	20.82%	$93.56	2.61%
48	1962	69.07	0.0297	-2.84%	$89.60	8.89%
49	1961	59.72	0.0328	18.94%	$89.74	4.29%
50	1960	58.03	0.0327	6.18%	$84.36	11.13%
51	1959	55.62	0.0324	7.57%	$91.55	-3.49%
52	1958	41.12	0.0448	39.74%	$101.22	-5.60%
53	1957	45.43	0.0431	-5.18%	$100.70	4.49%
54	1956	44.15	0.0424	7.14%	$113.00	-7.35%
55	1955	35.60	0.0438	28.40%	$116.77	0.20%
56	1954	25.46	0.0569	45.52%	$112.79	7.07%
57	1953	26.18	0.0545	2.70%	$114.24	2.24%
58	1952	24.19	0.0582	14.05%	$113.41	4.26%
59	1951	21.21	0.0634	20.39%	$123.44	-4.89%
60	1950	16.88	0.0665	32.30%	$125.08	1.89%
61	1949	15.36	0.0620	16.10%	$119.82	7.72%
62	1948	14.83	0.0571	9.28%	$118.50	4.49%
63	1947	15.21	0.0449	1.99%	$126.02	-2.79%
64	1946	18.02	0.0356	-12.03%	$126.74	2.59%
65	1945	13.49	0.0460	38.18%	$119.82	9.11%
66	1944	11.85	0.0495	18.79%	$119.82	3.34%
67	1943	10.09	0.0554	22.98%	$118.50	4.49%
68	1942	8.93	0.0788	20.87%	$117.63	4.14%
69	1941	10.55	0.0638	-8.98%	$116.34	4.55%
70	1940	12.30	0.0458	-9.65%	$112.39	7.08%
71	1939	12.50	0.0349	1.89%	$105.75	10.05%
72	1938	11.31	0.0784	18.36%	$99.83	9.94%
73	1937	17.59	0.0434	-31.36%	$103.18	0.63%
74	S&P 500 Return 1937--2009		10.8%			
75	A-rated Utility Bond Return		6.3%			
76	Risk Premium		4.5%			

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented.

SCHEDULE 4
COMPARATIVE RETURNS ON S&P UTILITY STOCK INDEX AND MOODY'S A-RATED UTILITY BONDS 1937 - 2009

Line No.	Year	S&P Utility Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Yield	Bond Return
1	2009				$68.43	
2	2008			-25.90%	$72.25	0.24%
3	2007			16.56%	$72.91	4.59%
4	2006			20.76%	$75.25	2.20%
5	2005			16.05%	$74.91	5.80%
6	2004			22.84%	$70.87	11.34%
7	2003			23.48%	$62.26	20.27%
8	2002			-14.73%	$57.44	15.35%
9						
10	2002	243.79	0.0362		$57.44	
11	2001	307.70	0.0287	-17.90%	$56.40	8.93%
12	2000	239.17	0.0413	32.78%	$52.60	14.82%
13	1999	253.52	0.0394	-1.72%	$63.03	-10.20%
14	1998	228.61	0.0457	15.47%	$62.43	7.38%
15	1997	201.14	0.0492	18.58%	$56.62	17.32%
16	1996	202.57	0.0454	3.83%	$60.91	-0.48%
17	1995	153.87	0.0584	37.49%	$50.22	29.26%
18	1994	168.70	0.0496	-3.83%	$60.01	-9.65%
19	1993	159.79	0.0537	10.95%	$53.13	20.48%
20	1992	149.70	0.0572	12.46%	$49.56	15.27%
21	1991	138.38	0.0607	14.25%	$44.84	19.44%
22	1990	146.04	0.0558	0.33%	$45.60	7.11%
23	1989	114.37	0.0699	34.68%	$43.06	15.18%
24	1988	106.13	0.0704	14.80%	$40.10	17.36%
25	1987	120.09	0.0588	-5.74%	$48.92	-9.84%
26	1986	92.06	0.0742	37.87%	$39.98	32.36%
27	1985	75.83	0.0860	30.00%	$32.57	35.05%
28	1984	68.50	0.0925	19.95%	$31.49	16.12%
29	1983	61.89	0.0948	20.16%	$29.41	20.65%
30	1982	51.81	0.1074	30.20%	$24.48	36.48%
31	1981	52.01	0.0978	9.40%	$29.37	-3.01%
32	1980	50.26	0.0953	13.01%	$34.69	-3.81%
33	1979	50.33	0.0893	8.79%	$43.91	-11.89%
34	1978	52.40	0.0791	3.96%	$49.09	-2.40%
35	1977	54.01	0.0714	4.16%	$50.95	4.20%
36	1976	46.99	0.0776	22.70%	$43.91	25.13%
37	1975	38.19	0.0920	32.24%	$41.76	14.75%
38	1974	48.60	0.0713	-14.29%	$52.54	-12.91%
39	1973	60.01	0.0556	-13.45%	$58.51	-3.37%
40	1972	60.19	0.0542	5.12%	$56.47	10.69%
41	1971	63.43	0.0504	-0.07%	$53.93	12.13%
42	1970	55.72	0.0561	19.45%	$50.46	14.81%
43	1969	68.65	0.0445	-14.38%	$62.43	-12.76%
44	1968	68.02	0.0435	5.28%	$66.97	-0.81%
45	1967	70.63	0.0392	0.22%	$78.69	-9.81%

Line No.	Year	S&P Utility Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Yield	Bond Return
46	1966	74.50	0.0347	-1.72%	$86.57	-4.48%
47	1965	75.87	0.0315	1.34%	$91.40	-0.91%
48	1964	67.26	0.0331	16.11%	$92.01	3.68%
49	1963	63.35	0.0330	9.47%	$93.56	2.61%
50	1962	62.69	0.0320	4.25%	$89.60	8.89%
51	1961	52.73	0.0358	22.47%	$89.74	4.29%
52	1960	44.50	0.0403	22.52%	$84.36	11.13%
53	1959	43.96	0.0377	5.00%	$91.55	-3.49%
54	1958	33.30	0.0487	36.88%	$101.22	-5.60%
55	1957	32.32	0.0487	7.90%	$100.70	4.49%
56	1956	31.55	0.0472	7.16%	$113.00	-7.35%
57	1955	29.89	0.0461	10.16%	$116.77	0.20%
58	1954	25.51	0.0520	22.37%	$112.79	7.07%
59	1953	24.41	0.0511	9.62%	$114.24	2.24%
60	1952	22.22	0.0550	15.36%	$113.41	4.26%
61	1951	20.01	0.0606	17.10%	$123.44	-4.89%
62	1950	20.20	0.0554	4.60%	$125.08	1.89%
63	1949	16.54	0.0570	27.83%	$119.82	7.72%
64	1948	16.53	0.0535	5.41%	$118.50	4.49%
65	1947	19.21	0.0354	-10.41%	$126.02	-2.79%
66	1946	21.34	0.0298	-7.00%	$126.74	2.59%
67	1945	13.91	0.0448	57.89%	$119.82	9.11%
68	1944	12.10	0.0569	20.65%	$119.82	3.34%
69	1943	9.22	0.0621	37.45%	$118.50	4.49%
70	1942	8.54	0.0940	17.36%	$117.63	4.14%
71	1941	13.25	0.0717	-28.38%	$116.34	4.55%
72	1940	16.97	0.0540	-16.52%	$112.39	7.08%
73	1939	16.05	0.0553	11.26%	$105.75	10.05%
74	1938	14.30	0.0730	19.54%	$99.83	9.94%
75	1937	24.34	0.0432	-36.93%	$103.18	0.63%
76	Return 1937—2009	Stocks	10.5%			
77		Bonds	6.3%			
78	Risk Premium		4.2%			

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented. Standard & Poor's discontinued its S&P Utilities Index in December 2001 and replaced its utilities stock index with separate indices for electric and natural gas utilities. In this study, the stock returns beginning in 2002 are based on the total returns for the EEI Index of U.S. shareholder-owned electric utilities, as reported by EEI on its website.
http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Pages/QtrlyFinancialUpdates.aspx

SCHEDULE 5
USING THE ARITHMETIC MEAN TO ESTIMATE
THE COST OF EQUITY CAPITAL

Consider an investment that in a given year generates a return of 30 percent with probability equal to .5 and a return of -10 percent with a probability equal to .5. For each one dollar invested, the possible outcomes of this investment at the end of year one are:

Ending Wealth	Probability
\$1.30	0.50
\$0.90	0.50

At the end of year two, the possible outcomes are:

Ending Wealth			Probability	Value x Probability
(1.30) (1.30)	=	\$1.69	0.25	0.4225
(1.30) (.9)	=	\$1.17	0.50	0.5850
(.9) (.9)	=	\$0.81	0.25	0.2025
Expected Wealth	=			\$1.21

The expected value of this investment at the end of year two is \$1.21. In a competitive capital market, the cost of equity is equal to the expected rate of return on an investment. In the above example, the cost of equity is that rate of return which will make the initial investment of one dollar grow to the expected value of \$1.21 at the end of two years. Thus, the cost of equity is the solution to the equation:

$$1(1+k)^2 = 1.21 \text{ or}$$

$$k = (1.21/1)^{.5} - 1 = 10\%.$$

The arithmetic mean of this investment is:

$$(30\%)\,(.5) + (-10\%)\,(.5) = 10\%.$$

Thus, the arithmetic mean is equal to the cost of equity capital.

The geometric mean of this investment is:

$$[(1.3)\,(.9)]^{.5} - 1 = .082 = 8.2\%.$$

Thus, the geometric mean is not equal to the cost of equity capital.

The lesson is obvious: for an investment with an uncertain outcome, the arithmetic mean is the best measure of the cost of equity capital.

SCHEDULE 6
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING SBBI 6.5 PERCENT RISK PREMIUM

LINE NO	RISK-FREE RATE	4.80%	FORECAST LONG-TERM TREASURY BOND YIELD
1	Beta	0.73	Average Beta Comparable Electric Companies
2	*Risk Premium*	*6.5%*	*Long-horizon SBBI risk premium*
3	Beta x Risk Premium	4.75%	
4	Flotation	0.27%	
5	CAPM cost of equity	9.8%	

Forecast Treasury bond yield from Bloomberg News survey of economists, February 12, 2009; SBBI® risk premium from *2009 Ibbotson® Risk Premia Over Time Report*, March 3, 2009, published by Morningstar®, Value Line beta for comparable companies from Value Line Investment Analyzer February 2009.

COMPARABLE COMPANY BETAS

LINE NO.	COMPANY	BETA	MARKET CAP $ (MIL)
1	Amer. Elec. Power	0.75	11,320
2	Avista Corp.	0.70	779
4	Dominion Resources	0.70	17,610
5	DPL Inc.	0.65	2,331
6	Duke Energy	0.60	17,043
7	Consol. Edison	0.65	9,908
8	Entergy Corp.	0.75	12,759
9	Exelon Corp.	0.90	31,082
10	FirstEnergy Corp.	0.85	12,974
11	FPL Group	0.80	18,528
13	NSTAR	0.70	3,436
14	Northeast Utilities	0.75	3,411
15	PG&E Corp.	0.65	13,979
16	Progress Energy	0.60	9,280
17	Pinnacle West Capital	0.70	2,652
18	Pepco Holdings	0.75	3,033
19	Portland General	0.65	1,027
21	SCANA Corp.	0.70	3,541
22	Southern Co.	0.55	23,478
23	Sempra Energy	0.95	10,119
25	Vectren Corp.	0.85	1,690
26	Wisconsin Energy	0.65	4,656
27	Westar Energy	0.80	1,830
28	Xcel Energy Inc.	0.70	7,966
29	Market-Wtd. Ave.	0.73	

Data from Value Line Investment Analyzer February 2009.

SCHEDULE 7
COMPARISON OF RISK PREMIA ON
S&P500 AND S&P UTILITIES 1937 – 2009

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
2008	-25.90	-35.19	3.67	-29.57	-38.85
2007	16.56	-1.27	4.63	11.93	-5.90
2006	20.76	13.20	4.79	15.97	8.41
2005	16.05	10.01	4.29	11.76	5.72
2004	22.84	5.94	4.27	18.57	1.66
2003	23.48	28.22	4.01	19.47	24.21
2002	-14.73	-20.05	4.61	-19.34	-24.66
2001	-17.90	-13.47	5.02	-22.92	-18.49
2000	32.78	-5.13	6.03	26.76	-11.16
1999	-1.72	15.46	5.64	-7.36	9.82
1998	15.47	31.25	5.26	10.20	25.98
1997	18.58	27.68	6.35	12.23	21.33
1996	3.83	27.02	6.44	-2.60	20.58
1995	37.49	34.93	6.58	30.91	28.35
1994	-3.83	1.05	7.08	-10.91	-6.03
1993	10.95	11.56	5.87	5.07	5.68
1992	12.46	7.50	7.01	5.45	0.49
1991	14.25	31.65	7.86	6.39	23.79
1990	0.33	-0.85	8.55	-8.21	-9.40
1989	34.68	22.76	8.50	26.18	14.26
1988	14.80	17.61	8.84	5.96	8.76
1987	-5.74	-2.13	8.38	-14.13	-10.52
1986	37.87	30.95	7.68	30.18	23.27
1985	30.00	25.83	10.62	19.38	15.20
1984	19.95	7.41	12.44	7.51	-5.03
1983	20.16	20.12	11.10	9.06	9.02
1982	30.20	28.96	13.00	17.19	15.96
1981	9.40	-7.00	13.91	-4.52	-20.91
1980	13.01	25.34	11.46	1.55	13.88
1979	8.79	16.52	9.44	-0.65	7.08
1978	3.96	15.80	8.41	-4.45	7.39
1977	4.16	-9.06	7.42	-3.26	-16.48
1976	22.70	10.96	7.61	15.09	3.35
1975	32.24	38.56	7.99	24.26	30.57
1974	-14.29	-20.86	7.56	-21.85	-28.42
1973	-13.45	-16.14	6.84	-20.30	-22.98
1972	5.12	17.58	6.21	-1.09	11.37
1971	-0.07	13.81	6.16	-6.23	7.65
1970	19.45	7.08	7.35	12.10	-0.27

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
1969	-14.38	-8.40	6.67	-21.06	-15.07
1968	5.28	10.45	5.65	-0.37	4.81
1967	0.22	16.05	5.07	-4.85	10.98
1966	-1.72	-6.48	4.92	-6.65	-11.41
1965	1.34	11.35	4.28	-2.94	7.07
1964	16.11	15.70	4.19	11.92	11.51
1963	9.47	20.82	4.00	5.47	16.81
1962	4.25	-2.84	3.95	0.31	-6.78
1961	22.47	18.94	3.88	18.59	15.05
1960	22.52	6.18	4.12	18.41	2.07
1959	5.00	7.57	4.33	0.67	3.24
1958	36.88	39.74	3.32	33.57	36.43
1957	7.90	-5.18	3.65	4.25	-8.82
1956	7.16	7.14	3.18	3.98	3.96
1955	10.16	28.40	2.82	7.35	25.58
1954	22.37	45.52	2.40	19.97	43.12
1953	9.62	2.70	2.81	6.80	-0.11
1952	15.36	14.05	2.48	12.88	11.57
1951	17.10	20.39	2.41	14.69	17.98
1950	4.60	32.30	2.05	2.55	30.25
1949	27.83	16.10	1.93	25.90	14.17
1948	5.41	9.28	2.15	3.26	7.13
1947	-10.41	1.99	1.85	-12.26	0.14
1946	-7.00	-12.03	1.74	-8.74	-13.77
1945	57.89	38.18	1.73	56.17	36.45
1944	20.65	18.79	2.09	18.56	16.70
1943	37.45	22.98	2.07	35.38	20.91
1942	17.36	20.87	2.11	15.26	18.76
1941	-28.38	-8.98	1.99	-30.36	-10.96
1940	-16.52	-9.65	2.20	-18.73	-11.85
1939	11.26	1.89	2.35	8.91	-0.46
1938	19.54	18.36	2.55	16.99	15.81
1937	-36.93	-31.36	2.69	-39.62	-34.05
Risk Premium 1937--2009				5.03	5.30
RP Utilities/RP SP500				0.95	

SCHEDULE 8
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN ON THE MARKET PORTFOLIO

Line No.	Risk-free rate	4.80%	Forecast Long-term Treasury bond yield
1	Beta	0.73	Average Beta Comparable Electric Companies
2	DCF S&P 500	13.4%	DCF Cost of Equity S&P 500 (see following)
3	Risk Premium	8.64%	
4	Beta x Risk Premium	6.31%	
5	CAPM cost of equity	11.1%	

Forecasted Treasury bond yield 2010 from Bloomberg News, February 12, 2009 (see Footnote 5 above), beta from Value Line Investment Analyzer February 2009.

SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS FOR S&P 500 COMPANIES

COMPANY	P_0	D_0	GROWTH	COST OF EQUITY
3M	55.30	2.04	10.30%	14.6%
ABBOTT LABORATORIES	52.00	1.60	11.52%	15.2%
AETNA	27.61	0.04	13.20%	13.4%
ALLERGAN	38.92	0.20	13.66%	14.3%
AMERICAN EXPRESS	18.03	0.72	10.25%	15.0%
AMERISOURCEBERGEN	34.75	0.40	12.17%	13.5%
AON	41.01	0.60	11.00%	12.7%
APPLIED MATS.	9.79	0.24	11.60%	14.5%
ASSURANT	25.46	0.56	9.50%	12.1%
BANK OF NEW YORK MELLON	25.29	0.96	10.75%	15.2%
BAXTER INTL.	54.45	1.04	12.47%	14.7%
BECTON DICKINSON	68.69	1.32	12.67%	15.0%
BEMIS	23.25	0.90	7.74%	12.2%
BEST BUY	27.19	0.56	12.84%	15.3%
BOEING	40.26	1.68	8.20%	13.0%
BURL.NTHN.SANTA FE C	70.22	1.60	9.73%	12.4%
CARDINAL HEALTH	34.71	0.56	11.08%	13.0%
CHESAPEAKE ENERGY	16.03	0.30	10.00%	12.2%
CHEVRON	72.12	2.60	9.13%	13.3%
CINTAS	23.02	0.47	10.83%	13.2%
CLOROX	53.02	1.84	9.67%	13.7%
CME GROUP	187.79	4.60	11.71%	14.6%
COCA COLA	43.72	1.64	8.13%	12.5%
COLGATE-PALM.	63.58	1.76	11.00%	14.3%
COMCAST 'A'	15.13	0.27	11.68%	13.8%
CONOCOPHILLIPS	47.98	1.88	8.07%	12.6%
COOPER INDS.	26.78	1.00	10.80%	15.2%
COSTCO WHOLESALE	48.28	0.64	12.44%	14.0%
CSX	31.61	0.88	8.82%	12.0%
CVS CAREMARK	27.37	0.30	13.75%	15.1%
DENTSPLY INTL.	26.28	0.20	13.80%	14.7%
DOMINION RES.	34.42	1.75	8.16%	14.1%
ELI LILLY	36.13	1.96	6.60%	12.8%
EMERSON ELECTRIC	33.32	1.32	10.33%	15.0%
ENSCO INTL.	27.83	0.10	13.33%	13.8%
ENTERGY	77.20	3.00	9.42%	14.0%
EQT	32.89	0.88	11.67%	14.8%
ESTEE LAUDER COS.'A'	27.45	0.55	10.33%	12.7%
EXELON	53.21	2.10	8.47%	13.0%
FAMILY DOLLAR STORES	26.30	0.54	11.25%	13.7%
FEDERATED INVRS.'B'	19.72	0.96	9.33%	15.0%
FEDEX	58.11	0.44	14.40%	15.3%

COMPANY	P_0	D_0	GROWTH	COST OF EQUITY
FIRSTENERGY	49.53	2.20	9.00%	14.2%
FLUOR	43.26	0.50	12.50%	13.9%
FPL GROUP	48.89	1.89	9.62%	14.1%
FRONTIER COMMUNICATIONS	8.11	1.00	0.72%	14.5%
GAP	12.39	0.34	9.88%	13.1%
GENERAL DYNAMICS	53.44	1.40	9.00%	12.0%
GOLDMAN SACHS GP.	79.16	1.40	12.00%	14.1%
GOODRICH	36.63	1.00	11.67%	14.9%
H&R BLOCK	20.81	0.60	11.80%	15.2%
HARTFORD FINL.SVS.GP.	13.03	0.20	10.75%	12.6%
HASBRO	25.99	0.80	9.00%	12.6%
HEWLETT-PACKARD	34.61	0.32	11.81%	12.9%
HOME DEPOT	22.45	0.90	9.50%	14.2%
HONEYWELL INTL.	31.05	1.21	9.86%	14.4%
ILLINOIS TOOL WORKS	33.18	1.24	8.80%	13.1%
INTERNATIONAL BUS.MCHS.	86.54	2.00	9.83%	12.5%
ITT	43.66	0.85	13.00%	15.3%
J M SMUCKER	42.57	1.28	8.67%	12.2%
JANUS CAPITAL GP.	6.60	0.04	11.20%	11.9%
JOHNSON & JOHNSON	56.73	1.84	8.30%	12.0%
KB HOME	12.65	0.25	10.50%	12.8%
KELLOGG	42.57	1.36	8.83%	12.5%
KRAFT FOODS	26.92	1.16	8.10%	13.1%
L3 COMMUNICATIONS	73.47	1.40	10.33%	12.6%
LOCKHEED MARTIN	77.35	2.28	11.50%	15.0%
LOWE'S COMPANIES	19.64	0.34	11.33%	13.4%
M&T BK.	48.50	2.80	6.30%	12.9%
MARRIOTT INTL.'A'	17.09	0.35	10.88%	13.3%
MARSH & MCLENNAN	21.95	0.80	10.00%	14.3%
MATTEL	14.00	0.75	9.00%	15.3%
MCDONALDS	58.60	2.00	8.87%	12.8%
MCKESSON	40.24	0.48	11.21%	12.6%
MEDTRONIC	31.94	0.75	11.35%	14.1%
METLIFE	28.50	0.74	11.64%	14.7%
MICROSOFT	18.92	0.52	10.22%	13.4%
MOLSON COORS BREWING 'B'	42.45	0.80	10.04%	12.2%
MOTOROLA	4.23	0.20	9.25%	14.8%
NATIONAL SEMICON.	10.67	0.32	9.80%	13.3%
NEWELL RUBBERMAID	9.30	0.42	9.50%	14.8%
NEWMONT MINING	38.60	0.40	13.77%	15.0%
NOBLE	24.56	0.16	13.47%	14.3%
NORFOLK SOUTHERN	41.56	1.36	10.63%	14.5%
NORTHERN TRUST	52.34	1.12	12.20%	14.7%
OCCIDENTAL PTL.	53.94	1.28	9.80%	12.6%
PACCAR	28.24	0.72	11.75%	14.8%

COMPANY	P_0	D_0	GROWTH	COST OF EQUITY
PEOPLES UNITED FINANCIAL	17.12	0.60	10.00%	14.1%
PEPSICO	51.65	1.70	9.45%	13.3%
PERKINELMER	14.06	0.28	12.33%	14.7%
PG&E	37.31	1.68	6.84%	12.0%
PINNACLE WEST CAP.	31.24	2.10	4.33%	11.9%
POLO RALPH LAUREN 'A'	41.69	0.20	14.00%	14.6%
PRAXAIR	60.27	1.60	10.12%	13.2%
PREC.CASTPARTS	59.18	0.12	13.33%	13.6%
PRINCIPAL FINL.GP.	16.54	0.45	11.47%	14.7%
PROCTER & GAMBLE	56.75	1.60	9.50%	12.8%
PROGRESS ENERGY	38.45	2.48	5.56%	12.9%
PULTE HOMES	10.86	0.16	11.67%	13.4%
QUEST DIAGNOSTICS	48.74	0.40	13.21%	14.2%
QWEST COMMS.INTL.	3.38	0.32	2.40%	13.0%
RAYTHEON 'B'	48.31	1.12	12.40%	15.2%
REGIONS FINL.NEW	6.31	0.40	6.00%	13.3%
RYDER SYSTEM	33.38	0.92	11.53%	14.8%
SEALED AIR	13.99	0.48	8.43%	12.4%
SOUTHWEST AIRLINES	7.71	0.02	13.33%	13.6%
STANLEY WORKS	31.75	1.28	8.67%	13.4%
STARWOOD HTLS.& RSTS. WORLDWIDE	16.41	0.90	7.00%	13.3%
STATE STREET	32.19	0.04	11.83%	12.0%
SUNTRUST BANKS	20.16	0.40	11.25%	13.6%
TARGET	33.24	0.64	12.67%	15.0%
TEXAS INSTS.	15.37	0.44	10.00%	13.4%
TEXTRON	11.26	0.08	11.65%	12.5%
TIFFANY & CO	22.04	0.68	10.83%	14.5%
TIME WARNER	9.36	0.25	11.51%	14.7%
TOTAL SYSTEM SERVICES	13.37	0.28	9.67%	12.1%
TRAVELERS COS.	40.30	1.20	9.00%	12.5%
UNITED TECHNOLOGIES	48.59	1.54	9.50%	13.2%
UNITEDHEALTH GP.	25.01	0.03	12.83%	13.0%
UNUM GROUP	15.24	0.30	10.00%	12.3%
V F	53.93	2.36	9.90%	15.1%
VERIZON COMMUNICATIONS	31.43	1.84	5.50%	12.2%
WAL MART STORES	52.13	0.95	11.50%	13.7%
WALGREEN	25.69	0.45	11.55%	13.6%
WISCONSIN ENERGY	42.68	1.35	9.13%	12.8%
WW GRAINGER	72.50	1.60	12.43%	15.1%
XCEL ENERGY	18.15	0.95	6.72%	12.7%
XTO EN.	35.70	0.50	11.40%	13.1%
YUM	28.22	0.76	11.84%	15.0%
YUM! BRANDS	28.92	0.76	11.84%	15.0%
Market Weighted Average				13.4%

Notes: In applying the DCF model to the S&P 500, I included in the DCF analysis only those companies in the S&P 500 group which pay a dividend, have a positive growth rate, and have at least three analysts' long-term growth estimates. I also eliminated those 25% of companies with the highest and lowest DCF results, a decision which had no impact on my CAPM estimate of the cost of equity.

D_0	=	Current dividend per Thomson Reuters.
P_0	=	Average of the monthly high and low stock prices during the three months ending February 2009 per Thomson Reuters.
FC	=	Flotation cost (5%) as a percentage of stock price.
g	=	I/B/E/S forecast of future earnings growth February 2009.
k	=	Cost of equity using the quarterly version of the DCF model shown below:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0(1-FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

SCHEDULE 9
AVERAGE MARKET VALUE CAPITAL STRUCTURE FOR COMPARABLE COMPANY GROUP

COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP $ (MIL)	TOTAL CAPITAL	%LONG-TERM DEBT	%PREFERRED	%MARKET EQUITY
Amer. Elec. Power	14,202	61	13,412	27,675	51.32%	0.22%	48.46%
Avista Corp.	635	0	1,055	1,690	37.58%	0.00%	62.42%
Dominion Resources	13,235	257	20,835	34,327	38.56%	0.75%	60.70%
DPL Inc.	1,542	23	2,648	4,213	36.59%	0.54%	62.86%
Duke Energy	9,498	0	18,986	28,484	33.34%	0.00%	66.66%
Consol. Edison	7,611	213	10,648	18,472	41.20%	1.15%	57.64%
Entergy Corp.	9,728	311	15,783	25,822	37.67%	1.21%	61.12%
Exelon Corp.	11,965	87	36,587	48,639	24.60%	0.18%	75.22%
FirstEnergy Corp.	8,869	0	14,809	23,678	37.46%	0.00%	62.54%
FPL Group	11,280	0	20,571	31,851	35.41%	0.00%	64.59%
NSTAR	2,501	43	3,897	6,442	38.83%	0.67%	60.50%
Northeast Utilities	4,401	116	3,745	8,262	53.27%	1.41%	45.33%
PG&E Corp.	8,171	252	13,866	22,289	36.66%	1.13%	62.21%
Progress Energy	8,737	93	10,441	19,271	45.34%	0.48%	54.18%
Pinnacle West Capital	3,127	0	3,239	6,366	49.12%	0.00%	50.88%
Pepco Holdings	4,735	0	3,591	8,326	56.87%	0.00%	43.13%
Portland General	1,313	0	1,218	2,531	51.88%	0.00%	48.12%
SCANA Corp.	2,879	113	4,184	7,176	40.12%	1.57%	58.30%
Southern Co.	14,143	1,080	28,660	43,883	32.23%	2.46%	65.31%
Sempra Energy	4,553	193	10,530	15,276	29.81%	1.26%	68.93%
Vectren Corp.	1,245	0	2,026	3,271	38.07%	0.00%	61.93%
Wisconsin Energy	3,173	30	4,908	8,111	39.11%	0.37%	60.51%
Westar Energy	1,890	21	2,219	4,130	45.76%	0.52%	53.73%
Xcel Energy Inc.	6,342	105	8,322	14,769	42.94%	0.71%	56.35%
Composite	155,775	2,999	256,179	414,953	37.54%	0.72%	61.74%

Source of data: Value Line Investment Analyzer January 2009.

SCHEDULE 10
ILLUSTRATION OF CALCULATION OF COST OF EQUITY REQUIRED FOR DUKE ENERGY CAROLINAS TO HAVE THE SAME WEIGHTED AVERAGE COST OF CAPITAL AS THE COMPARABLE GROUP

	Cost Rate		After-Tax Cost Rate
Tax Rate	39%		
Cost of Long-term Debt	6.32%		3.86%
Cost of Equity	11.1%		
Capital Structure Comparable Companies			
Capital Source	Percent	After-tax Cost Rate	Weighted Cost
Long-term Debt[11]	38.26%	3.86%	1.475%
Common Equity	61.74%	11.10%	6.853%
Total	100.00%		8.328%
Company Recommended Capital Structure			
Capital Source	Percent	After-tax Cost Rate	Weighted Cost
Long-term Debt	47.00%	3.86%	1.812%
Sum of Wtd. Cost of Debt and Preferred	47.00%		1.812%
(1) Ave. WACC Comparable Companies	8.328%		
(2) Wtd. Cost of Debt	1.812%		
(1) Less (2)	6.516%		
Cost of Equity (6.853 ÷ 0.53 = 12.3)	12.3%		
Weighted Average Cost of Capital			
Capital Source	Percent	After-tax Cost Rate	Weighted Cost
Long-term Debt	47.00%	3.86%	1.812%
Common Equity	53.00%	12.3%	6.516%
Total	100.00%		8.328%

[11] Since preferred stock represent an insignificant portion of the capital structure of my comparable company group, I conservatively include preferred stock with long-term debt.

APPENDIX 1
QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.

3606 Stoneybrook Drive
Durham, NC 27705
TEL. 919.383.6659 OR 919.383.1057
jim.vanderweide@duke.edu

James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance*;" a chapter for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques*, "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory," and written research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management. His articles have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business,* and *Computers and Operations Research.*

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the electric, gas, insurance, telecommunications, and water industries for more than 25 years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Energy Board (Canada), the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of 42 states and the District of Columbia, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in proceedings before the United States District Court for the District of New Hampshire; United States District Court for the Northern District of California; United States District Court for the District of Nebraska; United States District Court for the Eastern District of North Carolina; Superior Court of North Carolina, the United States Bankruptcy Court for the Southern District of West Virginia; and United States District Court for the Eastern District of Michigan. With respect to implementation of the Telecommunications Act of 1996, Dr. Vander Weide has testified in 30 states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

Telecommunications Companies

ALLTEL and its subsidiaries	Ameritech (now AT&T new)
AT&T (old)	Verizon (Bell Atlantic) and subsidiaries
Bell Canada/Nortel	BellSouth and its subsidiaries

Centel and its subsidiaries	Cincinnati Bell (Broadwing)
Cisco Systems	Citizens Telephone Company
Concord Telephone Company	*Contel and its subsidiaries*
Deutsche Telekom	GTE and subsidiaries (now Verizon)
Heins Telephone Company	Lucent Technologies
Minnesota Independent Equal Access Corp.	NYNEX and its subsidiaries (Verizon)
Pacific Telesis and its subsidiaries	Phillips County Cooperative Tel. Co.
Pine Drive Cooperative Telephone Co.	Roseville Telephone Company (SureWest)
Siemens	SBC Communications (now AT&T new)
Sherburne Telephone Company	Southern New England Telephone
The Stentor Companies	Sprint/United and its subsidiaries
Telefónica	Union Telephone Company
Woodbury Telephone Company	United States Telephone Association
U S West (Qwest)	Valor Telecommunications (Windstream)

<u>Electric, Gas, and Water Companies</u>
Alcoa Power Generating, Inc.
Alliant Energy
AltaLink, l.p.
Ameren
American Water Works
Atmos Energy
Central Illinois Public Service
Citizens Utilities
Consolidated Natural Gas and its subsidiaries
Dominion Resources
Duke Energy
Empire District Electric Company
EPCOR Distribution & Transmission Inc.
EPCOR Energy Alberta Inc.
FortisAlberta Inc.
Interstate Power Company
Iowa-American Water Company
Iowa-Illinois Gas and Electric
Iowa Southern
Kentucky-American Water Company
Kentucky Power Company
MidAmerican Energy and its subsidiaries
Nevada Power Company
NICOR
NOVA Gas Transmission Ltd.
North Shore Gas
PacifiCorp
PG&E
Peoples Energy and its subsidiaries
The Peoples Gas, Light and Coke Co.
Progress Energy
Public Service Company of North Carolina
PSE&G
Sempra Energy
South Carolina Electric and Gas
Southern Company and subsidiaries
Tennessee-American Water Company
Trans Québec & Maritimes Pipeline Inc.
United Cities Gas Company

<u>Insurance Companies</u>
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

North Carolina Natural Gas
Northern Natural Gas Company

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

In the 1970's, Dr. Vander Weide helped found University Analytics, Inc., which at that time was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

PUBLICATIONS
JAMES H. VANDER WEIDE

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A Unified Location Model for Cash Disbursements and Lock-Box Collections, *Journal of Bank Research*, Summer, 1976 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren Gorham and Lamont, 1978. Also reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

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A Strategy which Maximizes the Geometric Mean Return on Portfolio Investments, *Management Science*, June, 1977, Vol. 23, No. 10, pp. 1117-1123 (with S. Maier and D. Peterson).

A Decision Analysis Approach to the Computer Lease-Purchase Decision, *Computers and Operations Research*, Vol. 4, No. 3, September, 1977, pp. 167-172 (with S. Maier).

A Practical Approach to Short-run Financial Planning, *Financial Management*, Winter, 1978 (with S. Maier). Reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

Effectiveness of Regulation in the Electric Utility Industry,' *Journal of Economics and Business*, May, 1979 (with F. Tapon).

On the Decentralized Capital Budgeting Problem Under Uncertainty, *Management Science*, September 1979 (with B. Obel).

Expectations Data and the Predictive Value of Interim Reporting: A Comment, *Journal of Accounting Research*, Spring 1980 (with L. D. Brown, J. S. Hughes, and M. S. Rozeff).

General Telephone's Experience with a Short-run Financial Planning Model, *Cash Management Forum*, June 1980, Vol. 6, No. 1 (with J. Austin and S. Maier).

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Forecasting Disbursement Float, *Financial Management*, Spring 1981 (with S. Maier and D. Robinson).

Recent Developments in Management Science in Banking, *Management Science*, October 1981 (with K. Cohen and S. Maier).

Incentive Considerations in the Reporting of Leveraged Leases, *Journal of Bank Research,* April 1982 (with J. S. Hughes).

A Decision-Support System for Managing a Short-term Financial Instrument Portfolio, *Journal of Cash Management*, March 1982 (with S. Maier).

An Empirical Bayes Estimate of Market Risk, *Management Science*, July 1982 (with S. Maier and D. Peterson).

The Bond Scheduling Problem of the Multi-subsidiary Holding Company, *Management Science*, July 1982 (with K. Baker).

Deregulation and Locational Rents in Banking: a Comment, *Journal of Bank Research,* Summer 1983.

What Lockbox and Disbursement Models Really Do, *Journal of Finance,* May 1983 (with S. Maier).

Financial Management in the Short Run, *Handbook of Modern Finance,* edited by Dennis Logue, published by Warren, Gorham, & Lamont, Inc., New York, 1984.

Measuring Investors' Growth Expectations: Analysts vs. History, *The Journal of Portfolio Management*, Spring 1988 (with W. Carleton).

Entry Auctions and Strategic Behavior under Cross-Market Price Constraints, *International Journal of Industrial Organization*, 20 (2002) 611-629 (with J. Anton and N. Vettas).

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SUMMARY EXPERT TESTIMONY
JAMES H. VANDER WEIDE

SPONSOR	JURISDICTION	DATE	DOCKET NO.
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-2009	
EPCOR, FortisAlberta, AltaLink	Alberta Utilities Commission	Nov-08	
Trans Québec & Maritimes Pipeline Inc.	Alberta Utilities Commission	Nov-08	
Kentucky-American Water Company	Kentucky Public Service Commission	Oct-08	2008-00427
Atmos Energy	Tennessee Regulatory Authority	Oct-08	0800197
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-08	
Dorsey & Whitney LLP-Williams v. Gannon	Montana 2nd Judicial Dist. Ct. Silver Bow County	Apr-08	DV-02-201
Atmos Energy	Georgia	Mar-08	27163-U
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-08	
Trans Québec & Maritimes Pipeline Inc.	National Energy Board (Canada)	Dec-07	RH-1-2008
Xcel Energy	North Dakota	Dec-07	PU-07-776
Verizon Southwest	Texas	Nov-07	34723
Empire District Electric Company	Missouri	Oct-07	ER-2008-0093
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Sep-07	
Verizon North Inc. Contel of the South Inc.	Michigan	Aug-07	Case No. U-15210
Georgia Power Company	Georgia	Jun-07	25060-U
Duke Energy Carolinas	North Carolina	May-07	E-7 Sub 828 et al
MidAmerican Energy Company	Iowa	May-07	SPU-06-5 et al
Morrison & Foerster LLP-JDS Uniphase Securities Litigation	U.S. District Court Northern District California	Feb-07	C-02-1486-CW
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Dec-06	
San Diego Gas & Electric	FERC	Nov-06	ER07-284-000
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-06	
Union Electric Company d/b/a AmerenUE	Missouri	Jun-06	ER-2007-0002
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	May-06	
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Mar-06	
Empire District Electric Company	Missouri	Feb-06	ER-2006-0315
PacifiCorp Power & Light Company	Washington	Jan-06	UE-050684
Verizon Maine	Maine	Dec-05	2005-155
Winston & Strawn LLP-Cisco Systems Securities Litigation	U.S. District Court Northern District California	Nov-05	C-01-20418-JW
Dominion Virginia Power	Virginia	Nov-05	PUE-2004-00048
Bryan Cave LLP--Omniplex Comms. v. Lucent Technologies	U.S. District Court Eastern District Missouri	Sep-05	04CV00477 ERW
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-05	
Empire District Electric Company	Kansas	Sep-05	05-EPDE-980-RTS
Verizon Southwest	Texas	Jul-05	29315
PG&E Company	FERC	Jul-05	ER-05-1284
Dominion Hope	West Virginia	Jun-05	05-034-G42T
Empire District Electric Company	Missouri	Jun-05	EO-2005-0263
Verizon New England	U.S. District Court New Hampshire	May-05	04-CV-65-PB
San Diego Gas & Electric	California	May-05	05-05-012
Progress Energy	Florida	May-05	50078
Verizon Vermont	Vermont	Feb-05	6959
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Feb-05	
Verizon Florida	Florida	Jan-05	050059-TL
Verizon Illinois	Illinois	Jan-05	00-0812
Dominion Resources	North Carolina	Sep-04	E-22 Sub 412
Tennessee-American Water Company	Tennessee	Aug-04	04-00288
Valor Telecommunications of Texas, LP.	New Mexico	Jul-04	3495 Phase C
Alcoa Power Generating Inc.	North Carolina Property Tax Commission	Jul-04	02 PTC 162 and 02 PTC 709
PG&E Company	California	May-04	04-05-21
Verizon Northwest	Washington	Apr-04	UT-040788

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Verizon Northwest	Washington	Apr-04	UT-040788
Kentucky-American Water Company	Kentucky	Apr-04	2004-00103
MidAmerican Energy	South Dakota	Apr-04	NG4-001
Empire District Electric Company	Missouri	Apr-04	ER-2004-0570
Interstate Power and Light Company	Iowa	Mar-04	RPU-04-01
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-04	
Northern Natural Gas Company	FERC	Feb-04	RP04-155-000
Verizon New Jersey	New Jersey	Jan-04	TO00060356
Verizon	FCC	Jan-04	03-173, FCC 03-224
Verizon	FCC	Dec-03	03-173, FCC 03-224
Verizon California Inc.	California	Nov-03	R93-04-003,I93-04-002
Phillips County Telephone Company	Colorado	Nov-03	03S-315T
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Oct-03	
PG&E Company	FERC	Oct-03	ER04-109-000
Allstate Insurance Company	Texas Department of Insurance	Sep-03	2568
Verizon Northwest Inc.	Washington	Jul-03	UT-023003
Empire District Electric Company	Oklahoma	Jul-03	Case No. PUD 200300121
Verizon Virginia Inc.	FCC	Apr-03	CC-00218,00249,00251
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Apr-03	
Northern Natural Gas Company	FERC	Apr-03	RP03-398-000
MidAmerican Energy	Iowa	Apr-03	RPU-03-1, WRU-03-25-156
PG&E Company	FERC	Mar-03	ER03666000
Verizon Florida Inc.	Florida	Feb-03	981834-TP/990321-TP
Verizon North	Indiana	Feb-03	42259
San Diego Gas & Electric	FERC	Feb-03	ER03-601000
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-03	
Gulf Insurance Company	Superior Court, North Carolina	Jan-03	2000-CVS-3558
PG&E Company	FERC	Jan-03	ER03409000
Verizon New England Inc. New Hampshire	New Hampshire	Dec-02	DT 02-110
Verizon Northwest	Washington	Dec-02	UT 020406
PG&E Company	California	Dec-02	
MidAmerican Energy	Iowa	Nov-02	RPU-02-3, 02-8
MidAmerican Energy	Iowa	Nov-02	RPU-02-10
Verizon Michigan	US District Court Eastern District of Michigan	Sep-02	Civil Action No. 00-73208
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-02	
Verizon New England Inc. New Hampshire	New Hampshire	Aug-02	DT 02-110
Interstate Power Company	Iowa Board of Tax Review	Jul-02	832
PG&E Company	California	May-02	A 02-05-022 et al
Verizon New England Inc. Massachusetts	FCC	May-02	EB 02 MD 006
Verizon New England Inc. Rhode Island	Rhode Island	May-02	Docket No. 2681
NEUMEDIA, INC.	US Bankruptcy Court Southern District W. Virginia	Apr-02	Case No. 01-20873
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Mar-02	
MidAmerican Energy Company	Iowa	Mar-02	RPU 02 2
North Carolina Natural Gas Company	North Carolina	Feb-02	G21 Sub 424
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-02	
Verizon Pennsylvania	Pennsylvania	Dec-01	R-00016683
Verizon Florida	Florida	Nov-01	990648-TP
PG&E Company	FERC	Nov-01	ER0166000
Verizon Delaware	Delaware	Oct-01	96-324 Phase II
Florida Power Corporation	Florida	Sep-01	000824-EL
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-01	
Verizon Washington DC	District of Columbia	Jul-01	962
Verizon Virginia	FCC	Jul-01	CC-00218,00249,00251
Sherburne County Rural Telephone Company	Minnesota	Jul-01	P427/CI-00-712
Verizon New Jersey	New Jersey	Jun-01	TO01020095
Verizon Maryland	Maryland	May-01	8879
Verizon Massachusetts	Massachusetts	May-01	DTE 01-20

SPONSOR	JURISDICTION	DATE	DOCKET NO.
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Apr-01	
PG&E Company	FERC	Mar-01	ER011639000
Maupin Taylor & Ellis P.A.	National Association of Securities Dealers	Jan-01	99-05099
USTA	FCC	Oct-00	RM 10011
Verizon New York	New York	Oct-00	98-C-1357
Verizon New Jersey	New Jersey	Oct-00	TO00060356
PG&E Company	FERC	Oct-00	ER0166000
Verizon New Jersey	New Jersey	Sep-00	TO99120934
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-00	
PG&E Company	California	Aug-00	00-05-018
Verizon New York	New York	Jul-00	98-C-1357
PG&E Company	California	May-00	00-05-013
PG&E Company	FERC	Mar-00	ER00-66-000
PG&E Company	FERC	Mar-00	ER99-4323-000
Bell Atlantic	New York	Feb-00	98-C-1357
USTA	FCC	Jan-00	94-1, 96-262
MidAmerican Energy	Iowa	Nov-99	SPU-99-32
PG&E Company	California	Nov-99	99-11-003
PG&E Company	FERC	Nov-99	ER973255,981261,981685
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-99	
MidAmerican Energy	Illinois	Sep-99	99-0534
PG&E Company	FERC	Sep-99	ER99-4323-000
MidAmerican Energy	FERC	Jul-99	ER99-3887
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-99	
Bell Atlantic	Vermont	May-99	6167
Nevada Power Company	FERC	May-99	
Bell Atlantic, GTE, US West	FCC	Apr-99	CC98-166
Nevada Power Company	Nevada	Apr-99	
Bell Atlantic, GTE, US West	FCC	Mar-99	CC98-166
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-99	
PG&E Company	FERC	Mar-99	ER99-2326-000
MidAmerican Energy	Illinois	Mar-99	099-0310
PG&E Company	FERC	Feb-99	ER99-2358,2087,2351
MidAmerican Energy	US District Court, District of Nebraska	Feb-99	8:97 CV 346
Bell Atlantic, GTE, US West	FCC	Jan-99	CC98-166
The Southern Company	FERC	Jan-99	ER98-1096
Deutsche Telekom	Germany	Nov-98	
Telefonica	Spain	Nov-98	
Cincinnati Bell Telephone Company	Ohio	Oct-98	96899TPALT
MidAmerican Energy	Iowa	Sep-98	RPU 98-5
MidAmerican Energy	South Dakota	Sep-98	NG98-011
MidAmerican Energy	Iowa	Sep-98	SPU 98-8
GTE Florida Incorporated	Florida	Aug-98	980696-TP
GTE North and South	Illinois	Jun-98	960503
GTE Midwest Incorporated	Missouri	Jun-98	TO98329
GTE North and South	Illinois	May-98	960503
MidAmerican Energy	Iowa Board of Tax Review	May-98	835
San Diego Gas & Electric	California	May-98	98-05-024
GTE Midwest Incorporated	Nebraska	Apr-98	C1416
Carolina Telephone	North Carolina	Mar-98	P100Sub133d
GTE Southwest	Texas	Feb-98	18515
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-98	P100sub133d
Public Service Electric & Gas	New Jersey	Feb-98	PUC734897N,-734797N,BPUEO97070461,-07070462
GTE North	Minnesota	Dec-97	P999/M97909
GTE Northwest	Oregon	Dec-97	UM874
The Southern Company	FERC	Dec-97	ER981096000

SPONSOR	JURISDICTION	DATE	DOCKET NO.
GTE North	Pennsylvania	Nov-97	A310125F0002
Bell Atlantic	Rhode Island	Nov-97	2681
GTE North	Indiana	Oct-97	40618
GTE North	Minnesota	Oct-97	P442,407/5321/C1961541
GTE Southwest	New Mexico	Oct-97	96310TC,96344TC
GTE Midwest Incorporated	Iowa	Sep-97	RPU-96-7
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-97	
GTE Hawaiian Telephone	Hawaii	Aug-97	7702
The Stentor Companies	Canadian Radio-television and Telecommunications Commission	Jul-97	CRTC97-11
New England Telephone	Vermont	Jul-97	5713
Bell-Atlantic-New Jersey	New Jersey	Jun-97	TX95120631
Nevada Bell	Nevada	May-97	96-9035
New England Telephone	Maine	Apr-97	96-781
GTE North, Inc.	Michigan	Apr-97	U11281
Bell Atlantic-Virginia	Virginia	Apr-97	970005
Cincinnati Bell Telephone	Ohio	Feb-97	96899TPALT
Bell Atlantic - Pennsylvania	Pennsylvania	Feb-97	A310203,213,236,258F002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-97	
Bell Atlantic-Washington, D.C.	District of Columbia	Jan-97	962
Pacific Bell, Sprint, US West	FCC	Jan-97	CC 96-45
United States Telephone Association	FCC	Jan-97	CC 96-262
Bell Atlantic-Maryland	Maryland	Jan-97	8731
Bell Atlantic-West Virginia	West Virginia	Jan-97	961516, 1561, 1009TPC,961533TT
Poe, Hoof, & Reinhardt	Durham Cnty Superior Court Kountis vs. Circle K	Jan-97	95CVS04754
Bell Atlantic-Delaware	Delaware	Dec-96	96324
Bell Atlantic-New Jersey	New Jersey	Nov-96	TX95120631
Carolina Power & Light Company	FERC	Nov-96	OA96-198-000
New England Telephone	Massachusetts	Oct-96	DPU 96-73/74,-75, -80/81, -83, -94
New England Telephone	New Hampshire	Oct-96	96-252
Bell Atlantic-Virginia	Virginia	Oct-96	960044
Citizens Utilities	Illinois	Sep-96	96-0200, 96-0240
Union Telephone Company	New Hampshire	Sep-96	95-311
Bell Atlantic-New Jersey	New Jersey	Sep-96	TO-96070519
New York Telephone	New York	Sep-96	95-C-0657, 94-C-0095,91-C-1174
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-96	
MidAmerican Energy Company	Illinois	Sep-96	96-0274
MidAmerican Energy Company	Iowa	Sep-96	RPU96-8
United States Telephone Association	FCC	Mar-96	AAD-96.28
United States Telephone Association	FCC	Mar-96	CC 94-1 PhaseIV
Bell Atlantic - Maryland	Maryland	Mar-96	8715
Nevada Bell	Nevada	Mar-96	96-3002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-96	
Carolina Tel. and Telegraph Co, Central Tel Co	North Carolina	Feb-96	P7 sub 825, P10 sub 479
Oklahoma Rural Telephone Coalition	Oklahoma	Oct-95	PUD950000119
BellSouth	Tennessee	Oct-95	95-02614
Wake County, North Carolina	US District Court, Eastern Dist. NC	Oct-95	594CV643H2
Bell Atlantic - District of Columbia	District of Columbia	Sep-95	814 Phase IV
South Central Bell Telephone Company	Tennessee	Aug-95	95-02614
GTE South	Virginia	Jun-95	95-0019
Roseville Telephone Company	California	May-95	A.95-05-030
Bell Atlantic - New Jersey	New Jersey	May-95	TX94090388
Cincinnati Bell Telephone Company	Ohio	May-95	941695TPACE
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	May-95	727
Northern Illinois Gas	Illinois	May-95	95-0219
South Central Bell Telephone Company	Kentucky	Apr-95	94-121
Midwest Gas	South Dakota	Mar-95	
Virginia Natural Gas, Inc.	Virginia	Mar-95	PUE940054

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Hope Gas, Inc.	West Virginia	Mar-95	95-0003G42T
The Peoples Natural Gas Company	Pennsylvania	Feb-95	R-943252
and Coke Co., North Shore Gas, Iowa-Illinois Gas	Illinois	Jan-95	94-0403
and Electric, Central Illinois Public Service,	Illinois	Jan-95	94-0403
Northern Illinois Gas, The Peoples Gas, Light	Illinois	Jan-95	94-0403
United Cities Gas, and Interstate Power	Illinois	Jan-95	94-0403
Cincinnati Bell Telephone Company	Kentucky	Oct-94	94-355
Midwest Gas	Nebraska	Oct-94	
Midwest Power	Iowa	Sep-94	RPU-94-4
Bell Atlantic	FCC	Aug-94	CS 94-28, MM 93-215
Midwest Gas	Iowa	Jul-94	RPU-94-3
Bell Atlantic	FCC	Jun-94	CC 94-1
Nevada Power Company	Nevada	Jun-94	93-11045
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-551-TP-CSS
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-432-TP-ALT
GTE South/Contel	Virginia	Feb-94	PUC9300036
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-94	689
Bell of Pennsylvania	Pennsylvania	Jan-94	P930715
GTE South	South Carolina	Jan-94	93-504-C
United Telephone-Southeast	Tennessee	Jan-94	93-04818
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Sep-93	PUC920029
Bell Atlantic, NYNEX, Pacific Companies	FCC	Aug-93	MM 93-215
C&P, Centel, Contel, GTE, & United	Virginia	Aug-93	PUC920029
Chesapeake & Potomac Tel Virginia	Virginia	Aug-93	93-00-
GTE North	Illinois	Jul-93	93-0301
Midwest Power	Iowa	Jul-93	INU-93-1
Midwest Power	South Dakota	Jul-93	EL93-016
Chesapeake & Potomac Tel. Co. DC	District of Columbia	Jun-93	926
Cincinnati Bell	Ohio	Jun-93	93432TPALT
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jun-93	671
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-93	670
Pacific Bell Telephone Company	California	Mar-93	92-05-004
Minnesota Independent Equal Access Corp.	Minnesota	Mar-93	P3007/GR931
South Central Bell Telephone Company	Tennessee	Feb-93	92-13527
South Central Bell Telephone Company	Kentucky	Dec-92	92-523
Southern New England Telephone Company	Connecticut	Nov-92	92-09-19
Chesapeake & Potomac Tel. Co.CDC	District of Columbia	Nov-92	814
Diamond State Telephone Company	Delaware	Sep-92	PSC 92-47
New Jersey Bell Telephone Company	New Jersey	Sep-92	TO-92030958
Allstate Insurance Company	New Jersey Dept. of Insurance	Sep-92	INS 06174-92
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Aug-92	650
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-92	647
Midwest Gas Company	Minnesota	Aug-92	G010/GR92710
Pennsylvania-American Water Company	Pennsylvania	Jul-92	R-922428
Central Telephone Co. of Florida	Florida	Jun-92	920310-TL
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Jun-92	PUC920029
Chesapeake & Potomac Tel. Co. Maryland	Maryland	May-92	8462
Pacific Bell Telephone Company	California	Apr-92	92-05-004
Iowa Power Inc.	Iowa	Mar-92	RPU-92-2
Contel of Texas	Texas	Feb-92	10646
Southern Bell Telephone Company	Florida	Jan-92	880069-TL
Nevada Power Company	Nevada	Jan-92	92-1067
GTE South	Georgia	Dec-91	4003-U
GTE South	Georgia	Dec-91	4110-U
Allstate Insurance Company (property)	Texas Dept. of Insurance	Dec-91	1846
IPS Electric	Iowa	Oct-91	RPU-91-6
GTE South	Tennessee	Aug-91	91-05738
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-91	609

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Midwest Gas Company	Iowa	Jul-91	RPU-91-5
Pennsylvania-American Water Company	Pennsylvania	Jun-91	R-911909
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-91	606
Allstate Insurance Company	California Dept. of Insurance	May-91	RCD-2
Nevada Power Company	Nevada	May-91	91-5055
Kentucky Power Company	Kentucky	Apr-91	91-066
Chesapeake & Potomac Tel. Co.CD.C.	District of Columbia	Feb-91	850
Allstate Insurance Company	New Jersey Dept. of Insurance	Jan-91	INS-9536-90
GTE South	South Carolina	Nov-90	90-698-C
Southern Bell Telephone Company	Florida	Oct-90	880069-TL
GTE South	West Virginia	Aug-90	90-522-T-42T
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-90	R90-08-
The Travelers Indemnity Company	Pennsylvania Dept. of Insurance	Aug-90	R-90-06-23
Chesapeake & Potomac Tel. Co.-Maryland	*Maryland*	Jul-90	8274
Allstate Insurance Company	Pennsylvania Dept. of Insurance	Jul-90	R90-07-01
Central Tel. Co. of Florida	Florida	Jun-90	89-1246-TL
Citizens Telephone Company	North Carolina	Jun-90	P-12, SUB 89
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-90	568
Iowa Resources, Inc. and Midwest Energy	Iowa	Jun-90	SPU-90-5
Contel of Illinois	Illinois	May-90	90-0128
Southern New England Tel. Co.	Connecticut	Apr-90	89-12-05
Bell Atlantic	FCC	Apr-90	89-624 II
Pennsylvania-American Water Company	Pennsylvania	Mar-90	R-901652
Bell Atlantic	FCC	Feb-90	89-624
GTE South	Tennessee	Jan-90	
Allstate Insurance Company	California Dept. of Insurance	Jan-90	REB-1002
Bell Atlantic	FCC	Nov-89	87-463 II
Allstate Insurance Company	California Dept. of Insurance	Sep-89	REB-1006
Pacific Bell	California	Mar-89	87-11-0033
Iowa Power & Light	Iowa	Dec-88	RPU-88-10
Pacific Bell	California	Oct-88	88-05-009
Southern Bell	Florida	Apr-88	880069TL
Carolina Independent Telcos.	North Carolina	Apr-88	P-100, Sub 81
United States Telephone Association	U. S. Congress	Apr-88	
Carolina Power & Light	South Carolina	Mar-88	88-11-E
New Jersey Bell Telephone Co.	New Jersey	Feb-88	87050398
Carolina Power & Light	FERC	Jan-88	ER-88-224-000
Carolina Power & Light	North Carolina	Dec-87	E-2, Sub 537
Bell Atlantic	FCC	Nov-87	87-463
Diamond State Telephone Co.	Delaware	Jul-87	86-20
Central Telephone Co. of Nevada	Nevada	Jun-87	87-1249
ALLTEL	Florida	Apr-87	870076-PU
Southern Bell	Florida	Apr-87	870076-PU
Carolina Power & Light	North Carolina	Apr-87	E-2, Sub 526
So. New England Telephone Co.	Connecticut	Mar-87	87-01-02
Northern Illinois Gas Co.	Illinois	Mar-87	87-0032
Bell of Pennsylvania	Pennsylvania	Feb-87	860923
Carolina Power & Light	FERC	Jan-87	ER-87-240-000
Bell South	NTIA	Dec-86	61091-619
Heins Telephone Company	North Carolina	Oct-86	P-26, Sub 93
Public Service Co. of NC	North Carolina	Jul-86	G-5, Sub 207
Bell Atlantic	FCC	Feb-86	84-800 III
BellSouth	FCC	Feb-86	84-800 III
ALLTEL Carolina, Inc	North Carolina	Feb-86	P-118, Sub 39
ALLTEL Georgia, Inc.	Georgia	Jan-86	3567-U
ALLTEL Ohio	Ohio	Jan-86	86-60-TP-AIR
Western Reserve Telephone Co.	Ohio	Jan-86	85-1973-TP-AIR
New England Telephone & Telegraph	Maine	Dec-85	

SPONSOR	JURISDICTION	DATE	DOCKET NO.
ALLTEL-Florida	Florida	Oct-85	850064-TL
Iowa Southern Utilities	Iowa	Oct-85	RPU-85-11
Bell Atlantic	FCC	Sep-85	84-800 II
Pacific Telesis	FCC	Sep-85	84-800 II
Pacific Bell	California	Apr-85	85-01-034
United Telephone Co. of Missouri	Missouri	Apr-85	TR-85-179
South Carolina Generating Co.	FERC	Apr-85	85-204
South Central Bell	Kentucky	Mar-85	9160
New England Telephone & Telegraph	Vermont	Mar-85	5001
Chesapeake & Potomac Telephone Co.	West Virginia	Mar-85	84-747
Chesapeake & Potomac Telephone Co.	Maryland	Jan-85	7851
Central Telephone Co. of Ohio	Ohio	Dec-84	84-1431-TP-AIR
Ohio Bell	Ohio	Dec-84	84-1435-TP-AIR
Carolina Power & Light Co.	FERC	Dec-84	ER85-184000
BellSouth	FCC	Nov-84	84-800 I
Pacific Telesis	FCC	Nov-84	84-800 I
New Jersey Bell	New Jersey	Aug-84	848-856
Southern Bell	South Carolina	Aug-84	84-308-C
Pacific Power & Light Co.	Montana	Jul-84	84.73.8
Carolina Power & Light Co.	South Carolina	Jun-84	84-122-E
Southern Bell	Georgia	Mar-84	3465-U
Carolina Power & Light Co.	North Carolina	Feb-84	E-2, Sub 481
Southern Bell	North Carolina	Jan-84	P-55, Sub 834
South Carolina Electric & Gas	South Carolina	Nov-83	83-307-E
Empire Telephone Co.	Georgia	Oct-83	3343-U
Southern Bell	Georgia	Aug-83	3393-U
Carolina Power & Light Co.	FERC	Aug-83	ER83-765-000
General Telephone Co. of the SW	Arkansas	Jul-83	83-147-U
Heins Telephone Co.	North Carolina	Jul-83	No.26 Sub 88
General Telephone Co. of the NW	Washington	Jul-83	U-82-45
Leeds Telephone Co.	Alabama	Apr-83	18578
General Telephone Co. of California	California	Apr-83	83-07-02
North Carolina Natural Gas	North Carolina	Apr-83	G21 Sub 235
Carolina Power & Light	South Carolina	Apr-83	82-328-E
Eastern Illinois Telephone Co.	Illinois	Feb-83	83-0072
Carolina Power & Light	North Carolina	Feb-83	E-2 Sub 461
New Jersey Bell	New Jersey	Dec-82	8211-1030
Southern Bell	Florida	Nov-82	820294-TP
United Telephone of Missouri	Missouri	Nov-82	TR-83-135
Central Telephone Co. of NC	North Carolina	Nov-82	P-10 Sub 415
Concord Telephone Company	North Carolina	Nov-82	P-16 Sub 146
Carolina Telephone & Telegraph	North Carolina	Aug-82	P-7, Sub 670
Central Telephone Co. of Ohio	Ohio	Jul-82	82-636-TP-AIR
Southern Bell	South Carolina	Jul-82	82-294-C
General Telephone Co. of the SW	Arkansas	Jun-82	82-232-U
General Telephone Co. of Illinois	Illinois	Jun-82	82-0458
General Telephone Co. of the SW	Oklahoma	Jun-82	27482
Empire Telephone Co.	Georgia	May-82	3355-U
Mid-Georgia Telephone Co.	Georgia	May-82	3354-U
General Telephone Co. of the SW	Texas	Apr-82	4300
General Telephone Co. of the SE	Alabama	Jan-82	18199
Carolina Power & Light Co.	South Carolina	Jan-82	81-163-E
Elmore-Coosa Telephone Co.	Alabama	Nov-81	18215
General Telephone Co. of the SE	North Carolina	Sep-81	P-19, Sub 182
United Telephone Co. of Ohio	Ohio	Sep-81	81-627-TP-AIR
General Telephone Co. of the SE	South Carolina	Sep-81	81-121-C
Carolina Telephone & Telegraph	North Carolina	Aug-81	P-7, Sub 652
Southern Bell	North Carolina	Aug-81	P-55, Sub 794

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Woodbury Telephone Co.	Connecticut	Jul-81	810504
Central Telephone Co. of Virginia	Virginia	Jun-81	810030
United Telephone Co. of Missouri	Missouri	May-81	TR-81-302
General Telephone Co. of the SE	Virginia	Apr-81	810003
New England Telephone	Vermont	Mar-81	4546
Carolina Telephone & Telegraph	North Carolina	Aug-80	P-7, Sub 652
Southern Bell	North Carolina	Aug-80	P-55, Sub 784
General Telephone Co. of the SW	Arkansas	Jun-80	U-3138
General Telephone Co. of the SE	Alabama	May-80	17850
Southern Bell	North Carolina	Oct-79	P-55, Sub 777
Southern Bell	Georgia	Mar-79	3144-U
General Telephone Co. of the SE	Virginia	Mar-76	810038
General Telephone Co. of the SW	Arkansas	Feb-76	U-2693, U-2724
General Telephone Co. of the SE	Alabama	Sep-75	17058
General Telephone Co. of the SE	South Carolina	Jun-75	D-18269

APPENDIX 2
DERIVATION OF THE QUARTERLY DCF MODEL

The simple DCF Model assumes that a firm pays dividends only at the end of each year. Since firms in fact pay dividends quarterly and investors appreciate the time value of money, the annual version of the DCF Model generally underestimates the value investors are willing to place on the firm's expected future dividend stream. In these workpapers, we review two alternative formulations of the DCF Model that allow for the quarterly payment of dividends.

When dividends are assumed to be paid annually, the DCF Model suggests that the current price of the firm's stock is given by the expression:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n + P_n}{(1+k)^n} \quad (1)$$

where

P_0	=	current price per share of the firm's stock,
$D_1, D_2, \ldots, D_n$	=	expected annual dividends per share on the firm's stock,
P_n	=	price per share of stock at the time investors expect to sell the stock, and
k	=	return investors expect to earn on alternative investments of the same risk, i.e., the investors' required rate of return.

Unfortunately, expression (1) is rather difficult to analyze, especially for the purpose of estimating k. Thus, most analysts make a number of simplifying assumptions. First, they assume that dividends are expected to grow at the constant rate g into the indefinite future. Second, they assume that the stock price at time n is simply the present value of all dividends expected in periods subsequent to n. Third, they assume that the investors' required rate of return, k, exceeds the expected dividend growth rate g. Under the above simplifying assumptions, a firm's stock price may be written as the following sum:

$$P_0 = \frac{D_0(1+g)}{(1+k)} + \frac{D_0(1+g)^2}{(1+k)^2} + \frac{D_0(1+g)^3}{(1+k)^3} + \ldots , \qquad \textbf{(2)}$$

where the three dots indicate that the sum continues indefinitely.

As we shall demonstrate shortly, this sum may be simplified to:

$$P_0 = \frac{D_0(1+g)}{(k-g)}$$

First, however, we need to review the very useful concept of a geometric progression.

<u>Geometric Progression</u>

Consider the sequence of numbers 3, 6, 12, 24,..., where each number after the first is obtained by multiplying the preceding number by the factor 2. Obviously, this sequence of numbers may also be expressed as the sequence 3, 3 x 2, 3 x 2^2, 3 x 2^3, etc. This sequence is an example of a geometric progression.

<u>Definition</u>: A geometric progression is a sequence in which each term after the first is obtained by multiplying some fixed number, called the common ratio, by the preceding term.

A general notation for geometric progressions is: a, the first term, r, the common ratio, and n, the number of terms. Using this notation, any geometric progression may be represented by the sequence:

$$a, ar, ar^2, ar^3, \ldots, ar^{n-1}.$$

In studying the DCF Model, we will find it useful to have an expression for the sum of n terms of a geometric progression. Call this sum S_n. Then

$$S_n = a + ar + \ldots + ar^{n-1} \quad . \qquad (3)$$

However, this expression can be simplified by multiplying both sides of equation (3) by r and then subtracting the new equation from the old. Thus,

$$rS_n = ar + ar^2 + ar^3 + \ldots + ar^n$$

and

$$S_n - rS_n = a - ar^n \quad ,$$

or

$$(1 - r)\, S_n = a\,(1 - r^n) \ .$$

Solving for S_n, we obtain:

$$S_n = \frac{a(1 - r^n)}{(1 - r)} \qquad (4)$$

as a simple expression for the sum of n terms of a geometric progression. Furthermore, if $|r| < 1$, then S_n is finite, and as n approaches infinity, S_n approaches $a \div (1\text{-}r)$. Thus, for a geometric progression with an infinite number of terms and $|r| < 1$, equation (4) becomes:

$$S = \frac{a}{1 - r} \qquad (5)$$

<u>Application to DCF Model</u>

Comparing equation (2) with equation (3), we see that the firm's stock price (under the DCF assumption) is the sum of an infinite geometric progression with the first term

$$a = \frac{D_0(1 + g)}{(1 + k)}$$

and common factor

$$r = \frac{(1 + g)}{(1 + k)}$$

Applying equation (5) for the sum of such a geometric progression, we obtain

$$S = a \bullet \frac{1}{(1-r)} = \frac{D_0(1+g)}{(1+k)} \bullet \frac{1}{1-\frac{1+g}{1+k}} = \frac{D_0(1+g)}{(1+k)} \bullet \frac{1+k}{k-g} = \frac{D_0(1+g)}{k-g}$$

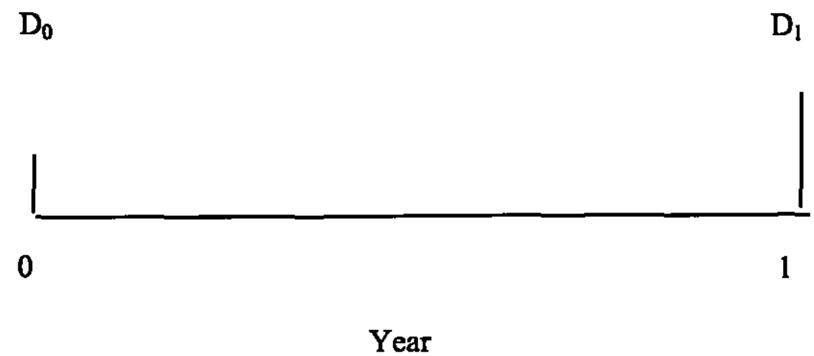
as we suggested earlier.

Quarterly DCF Model

The Annual DCF Model assumes that dividends grow at an annual rate of g% per year (see Figure 1).

Figure 1

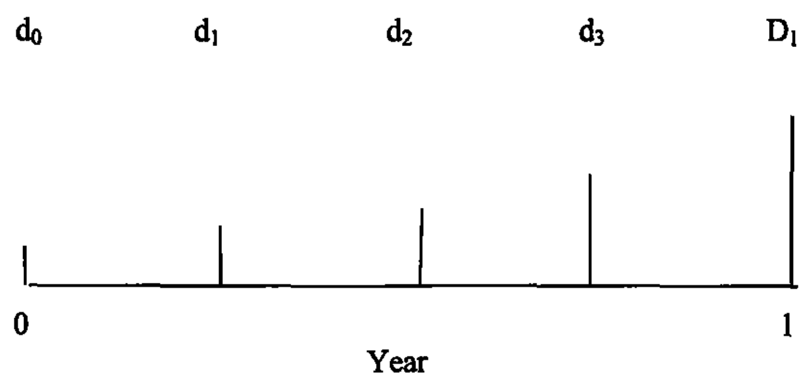
Annual DCF Model



$D_0 = 4d_0$ $\qquad\qquad$ $D_1 = D_0(1 + g)$

Figure 2

Quarterly DCF Model (Constant Growth Version)



$d_1 = d_0(1+g)^{.25}$ $\qquad\qquad$ $d_2 = d_0(1+g)^{.50}$

$d_3 = d_0(1+g)^{.75}$ $\qquad\qquad$ $d_4 = d_0(1+g)$

In the Quarterly DCF Model, it is natural to assume that quarterly dividend payments differ from the preceding quarterly dividend by the factor $(1 + g)^{.25}$, where g is expressed in terms of percent per year and the decimal .25 indicates that the growth has only occurred for one quarter of the year. (See Figure 2.) Using this assumption, along with the assumption of constant growth and $k > g$, we obtain a new expression for the firm's stock price, which takes account of the quarterly payment of dividends. This expression is:

$$P_0 = \frac{d_0(1+g)^{\frac{1}{4}}}{(1+k)^{\frac{1}{4}}} + \frac{d_0(1+g)^{\frac{2}{4}}}{(1+k)^{\frac{2}{4}}} + \frac{d_0(1+g)^{\frac{3}{4}}}{(1+k)^{\frac{3}{4}}} + \ldots \qquad (6)$$

where d_0 is the last quarterly dividend payment, rather than the last annual dividend payment. (We use a lower case d to remind the reader that this is not the annual dividend.)

Although equation (6) looks formidable at first glance, it too can be greatly simplified using the formula [equation (4)] for the sum of an infinite geometric progression. As the reader can easily verify, equation (6) can be simplified to:

$$P_0 = \frac{d_0(1+g)^{\frac{1}{4}}}{(1+k)^{\frac{1}{4}} - (1+g)^{\frac{1}{4}}} \qquad (7)$$

Solving equation (7) for k, we obtain a DCF formula for estimating the cost of equity under the quarterly dividend assumption:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1 \qquad (8)$$

An Alternative Quarterly DCF Model

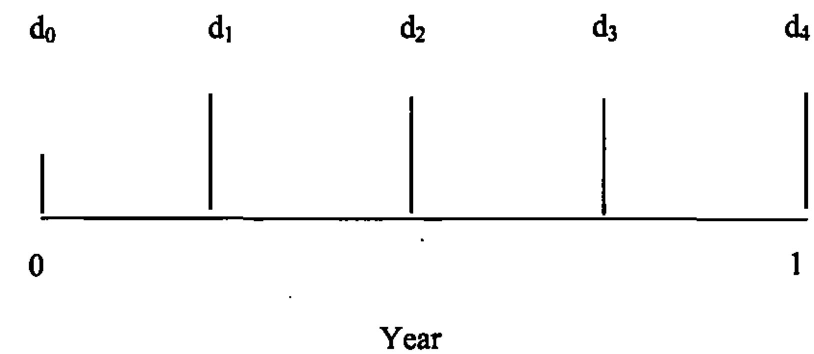
Although the constant growth Quarterly DCF Model [equation (8)] allows for the quarterly timing of dividend payments, it does require the assumption that the firm increases its dividend payments each quarter. Since this assumption is difficult for some analysts to accept, we now discuss a second Quarterly DCF Model that allows for constant quarterly dividend payments within each dividend year.

Assume then that the firm pays dividends quarterly and that each dividend payment is constant for four consecutive quarters. There are four cases to consider, with each case distinguished by varying assumptions about where we are evaluating the firm in relation to the time of its next dividend increase. (See Figure 3.)

Figure 3

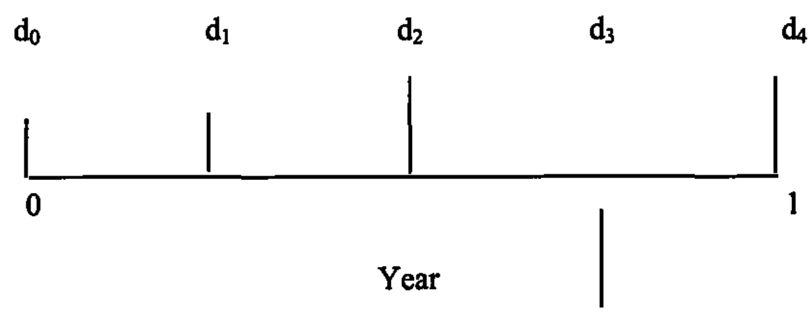
Quarterly DCF Model (Constant Dividend Version)

Case 1



$$d_1 = d_2 = d_3 = d_4 = d_0(1+g)$$

Case 2

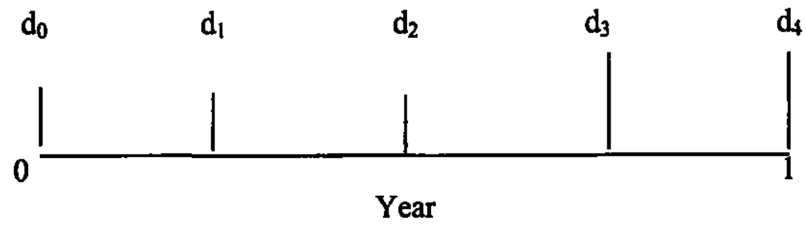


$$d_1 = d_0$$

$$d_2 = d_3 = d_4 = d_0(1+g)$$

<u>Figure 3</u> (continued)

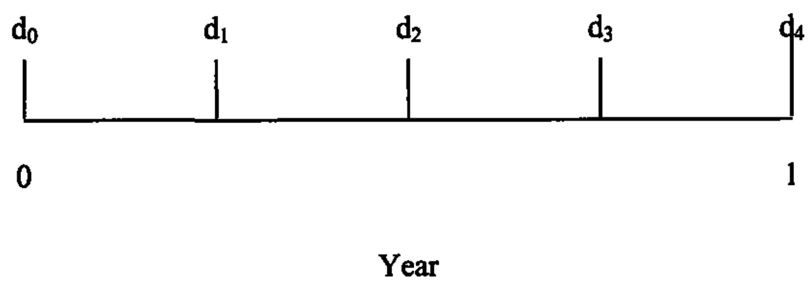
<u>Case 3</u>



$$d_1 = d_2 = d_0$$

$$d_3 = d_4 = d_0(1+g)$$

<u>Case 4</u>



$$d_1 = d_2 = d_3 = d_0$$

$$d_4 = d_0(1+g)$$

If we assume that the investor invests the quarterly dividend in an alternative investment of the same risk, then the amount accumulated by the end of the year will in all cases be given by

$$D_1^* = d_1\,(1+k)^{3/4} + d_2\,(1+k)^{1/2} + d_3\,(1+k)^{1/4} + d_4$$

where d_1, d_2, d_3 and d_4 are the four quarterly dividends. Under these new assumptions, the firm's stock price may be expressed by an Annual DCF Model of the form (2), with the exception that

$$D_1^* = d_1\,(1+k)^{3/4} + d_2\,(1+k)^{1/2} + d_3\,(1+k)^{1/4} + d_4 \quad \textbf{(9)}$$

is used in place of $D_0(1+g)$. But, we already know that the Annual DCF Model may be reduced to

$$P_0 = \frac{D_0(1+g)}{k-g}$$

Thus, under the assumptions of the second Quarterly DCF Model, the firm's cost of equity is given by

$$k = \frac{D_1^*}{P_0} + g \quad \textbf{(10)}$$

with D_1^* given by (9).

Although equation (10) looks like the Annual DCF Model, there are at least two very important practical differences. First, since D_1^* is always greater than $D_0(1+g)$, the estimates of the cost of equity are always larger (and more accurate) in the Quarterly Model (10) than in the Annual Model. Second, since D_1^* depends on k through equation (9), the unknown "k" appears on both sides of (10), and an iterative procedure is required to solve for k.

APPENDIX 3
ADJUSTING FOR FLOTATION COSTS IN DETERMINING
A PUBLIC UTILITY'S ALLOWED RATE OF RETURN ON EQUITY

I. Introduction

Regulation of public utilities is guided by the principle that utility revenues should be sufficient to allow recovery of all prudently incurred expenses, including the cost of capital. As set forth in the 1944 *Hope Natural Gas* Case [*Federal Power Comm'n v. Hope Natural Gas Co.* 320 U. S. 591 (1944) at 603], the U. S. Supreme Court states:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock....By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

Since the flotation costs arising from the issuance of debt and equity securities are an integral component of capital costs, this standard requires that the company's revenues be sufficient to fully recover flotation costs.

Despite the widespread agreement that flotation costs should be recovered in the regulatory process, several issues still need to be resolved. These include:

1. How is the term "flotation costs" defined? Does it include only the out-of-pocket costs associated with issuing securities (e. g., legal fees, printing costs, selling and underwriting expenses), or does it also include the reduction in a security's price that frequently accompanies flotation (i. e., market pressure)?
2. What should be the time pattern of cost recovery? Should a company be allowed to recover flotation costs immediately, or should flotation costs be recovered over the life of the issue?
3. For the purposes of regulatory accounting, should flotation costs be included as an expense? As an addition to rate base? Or as an additional element of a firm's allowed rate of return?
4. Do existing regulatory methods for flotation cost recovery allow a firm ***full*** recovery of flotation costs?

In this paper, I review the literature pertaining to the above issues and discuss my own views regarding how this literature applies to the cost of equity for a regulated firm.

II. Definition of Flotation Cost

The value of a firm is related to the future stream of net cash flows (revenues minus expenses measured on a cash basis) that can be derived from its assets. In the process of acquiring assets, a firm incurs certain expenses which reduce its value. Some of these expenses or costs are directly associated with revenue production in one period (e. g., wages, cost of goods sold), others are more properly associated with revenue production in many periods (e. g., the acquisition cost of plant and equipment). In either case, the word "cost" refers to any item that reduces the value of a firm.

If this concept is applied to the act of issuing new securities to finance asset purchases, many items are properly included in issuance or flotation costs. These include: (1) compensation received by investment bankers for underwriting services, (2) legal fees, (3) accounting fees, (4) engineering fees, (5) trustee's fees, (6) listing fees, (7) printing and engraving expenses, (8) SEC registration fees, (9) Federal Revenue Stamps, (10) state taxes, (11) warrants granted to underwriters as extra compensation, (12) postage expenses, (13) employees' time, (14) market pressure, and (15) the offer discount. The finance literature generally divides these flotation cost items into three categories, namely, underwriting expenses, issuer expenses, and price effects.

III. Magnitude of Flotation Costs

The finance literature contains several studies of the magnitude of the flotation costs associated with new debt and equity issues. These studies differ primarily with regard to the time period studied, the sample of companies included, and the source of data. The flotation cost studies generally agree, however, that for large issues, underwriting expenses represent approximately one and one-half percent of the proceeds of debt issues and three to five percent of the proceeds of seasoned equity issues. They also agree that issuer expenses represent approximately 0.5 percent of both debt and equity issues, and that the announcement of an equity issue reduces the company's stock price by at least two to three percent of the proceeds from the stock issue. Thus, total flotation costs represent approximately two percent[12] of the proceeds from debt issues, and five and one-half to eight and one-half percent of the proceeds of equity issues.

Lee *et. al.* [14] is an excellent example of the type of flotation cost studies found in the finance literature. The Lee study is a comprehensive recent study of the underwriting and issuer costs associated with debt and equity issues for both utilities and non-utilities. The results of the Lee *et. al.* study are reproduced in Tables 1 and 2. Table 1 demonstrates that the total underwriting and issuer expenses for the 1,092 debt issues in their study averaged 2.24 percent of the proceeds of the issues, while the total underwriting and issuer costs for the 1,593 seasoned equity issues in their study averaged 7.11 percent of the proceeds of the new issue. Table 1 also demonstrates that the total underwriting and issuer costs of seasoned equity offerings, as a percent of proceeds, decline with the size of the issue. For issues above $60 million, total underwriting and issuer costs amount to from three to five percent of the amount of the proceeds.

Table 2 reports the total underwriting and issuer expenses for 135 utility debt issues and 136 seasoned utility equity issues. Total underwriting and issuer expenses for utility bond offerings averaged 1.47 percent of the amount of the proceeds and for seasoned

[12] The two percent flotation cost on debt only recognizes the cost of newly-issued debt. When interest rates decline, many companies exercise the call provisions on higher cost debt and reissue debt at lower rates. This process involves reacquisition costs that are not included in the academic studies. If reacquisition costs were included in the academic studies, debt flotation costs could increase significantly.

utility equity offerings averaged 4.92 percent of the amount of the proceeds. Again, there are some economies of scale associated with larger equity offerings. Total underwriting and issuer expenses for equity offerings in excess of 40 million dollars generally range from three to four percent of the proceeds.

The results of the Lee study for large equity issues are consistent with results of earlier studies by Bhagat and Frost [4], Mikkelson and Partch [17], and Smith [24]. Bhagat and Frost found that total underwriting and issuer expenses average approximately four and one-half percent of the amount of proceeds from negotiated utility offerings during the period 1973 to 1980, and approximately three and one-half percent of the amount of the proceeds from competitive utility offerings over the same period. Mikkelson and Partch found that total underwriting and issuer expenses average five and one-half percent of the proceeds from seasoned equity offerings over the 1972 to 1982 period. Smith found that total underwriting and issuer expenses for larger equity issues generally amount to four to five percent of the proceeds of the new issue.

The finance literature also contains numerous studies of the decline in price associated with sales of large blocks of stock to the public. These articles relate to the price impact of: (1) initial public offerings; (2) the sale of large blocks of stock from one investor to another; and (3) the issuance of seasoned equity issues to the general public. All of these studies generally support the notion that the announcement of the sale of large blocks of stock produces a decline in a company's share price. The decline in share price for initial public offerings is significantly larger than the decline in share price for seasoned equity offerings; and the decline in share price for public utilities is less than the decline in share price for non-public utilities. A comprehensive study of the magnitude of the decline in share price associated specifically with the sale of new equity by public utilities is reported in Pettway [19], who found the market pressure effect for a sample of 368 public utility equity sales to be in the range of two to three percent. This decline in price is a real cost to the utility, because the proceeds to the utility depend on the stock price on the day of issue.

In addition to the price decline associated with the announcement of a new equity issue, the finance literature recognizes that there is also a price decline associated with the actual issuance of equity securities. In particular, underwriters typically sell seasoned new equity securities to investors at a price lower than the closing market price on the day preceding the issue. The Rules of Fair Practice of the National Association of Securities Dealers require that underwriters not sell shares at a price above the offer price. Since the offer price represents a binding constraint to the underwriter, the underwriter tends to set the offer price slightly below the market price on the day of issue to compensate for the risk that the price received by the underwriter may go down, but can not increase. Smith provides evidence that the offer discount tends to be between 0.5 and 0.8 percent of the proceeds of an equity issue. I am not aware of any similar studies for debt issues.

In summary, the finance literature provides strong support for the conclusion that total underwriting and issuer expenses for public utility debt offerings represent approximately two percent of the amount of the proceeds, while total underwriting and issuer expenses for public utility equity offerings represent at least four to five percent of the amount of the proceeds. In addition, the finance literature supports the conclusion that the cost associated with the decline in stock price at the announcement date represents approximately two to three percent as a result of a large public utility equity issue.

IV. Time Pattern Of Flotation Cost Recovery

Although flotation costs are incurred only at the time a firm issues new securities, there is no reason why an issuing firm ought to recognize the expense only in the current period. In fact, if assets purchased with the proceeds of a security issue produce revenues over many years, a sound argument can be made in favor of recognizing flotation expenses over a reasonably lengthy period of time. Such recognition is certainly consistent with the generally accepted accounting principle that the time pattern of expenses match the time pattern of revenues, and it is also consistent with the normal treatment of debt flotation expenses in both regulated and unregulated industries.

In the context of a regulated firm, it should be noted that there are many possible time patterns for the recovery of flotation expenses. However, if it is felt that flotation expenses are most appropriately recovered over a period of years, then it should be recognized that investors must also be compensated for the passage of time. That is to say, the value of an investor's capital will be reduced if the expenses are merely distributed over time, without any allowance for the time value of money.

V. Accounting For Flotation Cost In A Regulatory Setting

In a regulatory setting, a firm's revenue requirements are determined by the equation:

Revenue Requirement = Total Expenses + Allowed Rate of Return x Rate Base

Thus, there are three ways in which an issuing firm can account for and recover its flotation expenses: (1) treat flotation expenses as a current expense and recover them immediately; (2) include flotation expenses in rate base and recover them over time; and (3) adjust the allowed rate of return upward and again recover flotation expenses over time. Before considering methods currently being used to recover flotation expenses in a regulatory setting, I shall briefly consider the advantages and disadvantages of these three basic recovery methods.

Expenses. Treating flotation costs as a current expense has several advantages. Because it allows for recovery at the time the expense occurs, it is not necessary to compute amortized balances over time and to debate which interest rate should be applied to these balances. A firm's stockholders are treated fairly, and so are the firm's customers, because they pay neither more nor less than the actual flotation expense. Since flotation costs are relatively small compared to the total revenue requirement, treatment as a current expense does not cause unusual rate hikes in the year of flotation, as would the introduction of a large generating plant in a state that does not allow Construction Work in Progress in rate base.

On the other hand, there are two major disadvantages of treating flotation costs as a current expense. First, since the asset purchased with the acquired funds will likely generate revenues for many years into the future, it seems unfair that current ratepayers should bear the full cost of issuing new securities, when future ratepayers share in the benefits. Second, this method requires an estimate of the underpricing effect on each security issue. Given the difficulties involved in measuring the extent of underpricing, it may be more accurate to estimate the average underpricing allowance for many securities than to estimate the exact figure for one security.

<u>Rate Base</u>. In an article in *Public Utilities Fortnightly,* Bierman and Hass [5] recommend that flotation costs be treated as an intangible asset that is included in a firm's rate base along with the assets acquired with the stock proceeds. This approach has many advantages. For ratepayers, it provides a better match between benefits and expenses: the future ratepayers who benefit from the financing costs contribute the revenues to recover these costs. For investors, if the allowed rate of return is equal to the investors' required rate of return, it is also theoretically fair since they are compensated for the opportunity cost of their investment (including both the time value of money and the investment risk).

Despite the compelling advantages of this method of cost recovery, there are several disadvantages that probably explain why it has not been used in practice. First, a firm will only recover the proper amount for flotation expenses if the rate base is multiplied by the appropriate cost of capital. To the extent that a commission under or over estimates the cost of capital, a firm will under or over recover its flotation expenses. Second, it is may be both legally and psychologically difficult for commissioners to include an intangible asset in a firm's rate base. According to established legal doctrine, assets are to be included in rate base only if they are "used and useful" in the public service. It is unclear whether intangible assets such as flotation expenses meet this criterion.

<u>Rate of Return</u>. The prevailing practice among state regulators is to treat flotation expenses as an additional element of a firm's cost of capital or allowed rate of return. This method is similar to the second method above (treatment in rate base) in that some part of the initial flotation cost is amortized over time. However, it has a disadvantage not shared by the rate base method. If flotation cost is included in rate base, it is fairly easy to keep track of the flotation cost on each new equity issue and see how it is recovered over time. Using the rate of return method, it is not possible to track the flotation cost for specific issues because the flotation cost for a specific issue is never recorded. Thus, it is not clear to participants whether a current allowance is meant to recover (1) flotation costs actually incurred in a test period, (2) expected future flotation costs, or (3) past flotation costs. This confusion never arises in the treatment of debt flotation costs. Because the exact costs are recorded and explicitly amortized over time, participants recognize that current allowances for debt flotation costs are meant to recover some fraction of the flotation costs on all past debt issues.

VI. Existing Regulatory Methods

Although most state commissions prefer to let a regulated firm recover flotation expenses through an adjustment to the allowed rate of return, there is considerable controversy about the magnitude of the required adjustment. The following are some of the most frequently asked questions: (1) Should an adjustment to the allowed return be made every year, or should the adjustment be made only in those years in which new equity is raised? (2) Should an adjusted rate of return be applied to the entire rate base, or should it be applied only to that portion of the rate base financed with paid-in capital (as opposed to retained earnings)? (3) What is the appropriate formula for adjusting the rate of return?

This section reviews several methods of allowing for flotation cost recovery. Since the regulatory methods of allowing for recovery of debt flotation costs is well known and widely accepted, I will begin my discussion of flotation cost recovery procedures by describing the widely accepted procedure of allowing for debt flotation cost recovery.

Debt Flotation Costs

Regulators uniformly recognize that companies incur flotation costs when they issue debt securities. They typically allow recovery of debt flotation costs by making an adjustment to both the cost of debt and the rate base (see Brigham [6]). Assume that: (1) a regulated company issues $100 million in bonds that mature in 10 years; (2) the interest rate on these bonds is seven percent; and (3) flotation costs represent four percent of the amount of the proceeds. Then the cost of debt for regulatory purposes will generally be calculated as follows:

$$\begin{aligned}\text{Cost of Debt} &= \frac{\text{Interest expense} + \text{Amortization of flotation costs}}{\text{Principal value - Unamortized flotation costs}} \\ &= \frac{\$7{,}000{,}000 + \$400{,}000}{\$100{,}000{,}000 - \$4{,}000{,}000} \\ &= 7.71\%\end{aligned}$$

Thus, current regulatory practice requires that the cost of debt be adjusted upward by approximately 71 basis points, in this example, to allow for the recovery of debt flotation costs. This example does not include losses on reacquisition of debt. The flotation cost allowance would increase if losses on reacquisition of debt were included.

The logic behind the traditional method of allowing for recovery of debt flotation costs is simple. Although the company has issued $100 million in bonds, it can only invest $96 million in rate base because flotation costs have reduced the amount of funds received by $4 million. If the company is not allowed to earn a 71 basis point higher rate of return on the $96 million invested in rate base, it will not generate sufficient cash flow to pay the seven percent interest on the $100 million in bonds it has issued. Thus, proper regulatory treatment is to increase the required rate of return on debt by 71 basis points.

Equity Flotation Costs

The finance literature discusses several methods of recovering equity flotation costs. Since each method stems from a specific model, (i. e., set of assumptions) of a firm and its cash flows, I will highlight the assumptions that distinguish one method from another.

<u>**Arzac and Marcus**</u>. Arzac and Marcus [2] study the proper flotation cost adjustment formula for a firm that makes continuous use of retained earnings and external equity

financing and maintains a constant capital structure (debt/equity ratio). They assume at the outset that underwriting expenses and underpricing apply only to new equity obtained from external sources. They also assume that a firm has previously recovered all underwriting expenses, issuer expenses, and underpricing associated with previous issues of new equity.

To discuss and compare various equity flotation cost adjustment formulas, Arzac and Marcus make use of the following notation:

k	=	an investors' required return on equity
r	=	a utility's allowed return on equity base
S	=	value of equity in the absence of flotation costs
S_f	=	value of equity net of flotation costs
K_t	=	equity base at time t
E_t	=	total earnings in year t
D_t	=	total cash dividends at time t
b	=	$(E_t\text{-}D_t) \div E_t$ = retention rate, expressed as a fraction of earnings
h	=	new equity issues, expressed as a fraction of earnings
m	=	equity investment rate, expressed as a fraction of earnings, $m = b + h < 1$
f	=	flotation costs, expressed as a fraction of the value of an issue.

Because of flotation costs, Arzac and Marcus assume that a firm must issue a greater amount of external equity each year than it actually needs. In terms of the above notation, a firm issues $hE_t \div (1\text{-}f)$ to obtain hE_t in external equity funding. Thus, each year a firm loses:

Equation 3

$$L = \frac{hE_t}{1-f} - hE_t = \frac{f}{1-f} \times hE_t$$

due to flotation expenses. The present value, V, of all future flotation expenses is:

Equation 4

$$V = \sum_{t=1}^{\infty} \frac{fhE_t}{(1-f)(1+k)^t} = \frac{fh}{1-f} \times \frac{rK_0}{k-mr}$$

To avoid diluting the value of the initial stockholder's equity, a regulatory authority needs to find the value of r, a firm's allowed return on equity base, that equates the value of equity net of flotation costs to the initial equity base ($S_f = K_0$). Since the value of equity net of flotation costs equals the value of equity in the absence of flotation costs minus the present value of flotation costs, a regulatory authority needs to find that value of r that solves the following equation:

$$S_f = S - L.$$

This value is:

Equation 5

$$r = \frac{k}{1 - \frac{fh}{1-f}}.$$

To illustrate the Arzac-Marcus approach to adjusting the allowed return on equity for the effect of flotation costs, suppose that the cost of equity in the absence of flotation costs is 12 percent. Furthermore, assume that a firm obtains external equity financing each year equal to 10 percent of its earnings and that flotation expenses equal 5 percent of the value of each issue. Then, according to Arzac and Marcus, the allowed return on equity should be:

$$r = \frac{.12}{1 - \frac{(.05).(.1)}{.95}} = .1206 = 12.06\%$$

<u>Summary</u>. With respect to the three questions raised at the beginning of this section, it is evident that Arzac and Marcus believe the flotation cost adjustment should be applied each year, since continuous external equity financing is a fundamental assumption of their model. They also believe that the adjusted rate of return should be applied to the entire equity-financed portion of the rate base because their model is based on the assumption that the flotation cost adjustment mechanism will be applied to the entire equity financed portion of the rate base. Finally, Arzac and Marcus recommend a flotation cost adjustment formula, Equation (3), that implicitly excludes recovery of financing costs associated with financing in previous periods and includes only an allowance for the fraction of equity financing obtained from external sources.

<u>Patterson</u>. The Arzac-Marcus flotation cost adjustment formula is significantly different from the conventional approach (found in many introductory textbooks) which recommends the adjustment equation:

Equation 6

$$r = \frac{D_t}{P_{t-1}(1-f)} + g$$

where P_{t-1} is the stock price in the previous period and g is the expected dividend growth rate. Patterson [18] compares the Arzac-Marcus adjustment formula to the conventional approach and reaches the conclusion that the Arzac-Marcus formula effectively expenses issuance costs as they are incurred, while the conventional approach effectively amortizes them over an assumed infinite life of the equity issue. Thus, the conventional formula is similar to the formula for the recovery of debt flotation costs: it is not meant to compensate investors for the flotation costs of future issues, but instead is meant to compensate investors for the flotation costs of previous issues. Patterson argues that the conventional approach is more appropriate for rate making purposes because the plant purchased with external equity funds will yield benefits over many future periods.

Illustration. To illustrate the Patterson approach to flotation cost recovery, assume that a newly organized utility sells an initial issue of stock for $100 per share, and that the utility plans to finance all new investments with retained earnings. Assume also that: (1) the initial dividend per share is six dollars; (2) the expected long-run dividend growth rate is six percent; (3) the flotation cost is five percent of the amount of the proceeds; and (4) the payout ratio is 51.28 percent. Then, the investor's required rate of return on equity is [k = (D/P) + g = 6 percent + 6 percent = 12 percent]; and the flotation-cost-adjusted cost of equity is [6 percent (1/.95) + 6 percent = 12.316 percent].

The effects of the Patterson adjustment formula on the utility's rate base, dividends, earnings, and stock price are shown in Table 3. We see that the Patterson formula allows earnings and dividends to grow at the expected six percent rate. We also see that the present value of expected future dividends, $100, is just sufficient to induce investors to part with their money. If the present value of expected future dividends were less than $100, investors would not have been willing to invest $100 in the firm. Furthermore, the present value of future dividends will only equal $100 if the firm is allowed to earn the 12.316 percent flotation-cost-adjusted cost of equity on its entire rate base.

Summary. Patterson's opinions on the three issues raised in this section are in stark contrast to those of Arzac and Marcus. He believes that: (1) a flotation cost adjustment should be applied in every year, regardless of whether a firm issues any new equity in each year; (2) a flotation cost adjustment should be applied to the entire equity-financed portion of the rate base, including that portion financed by retained earnings; and (3) the rate of return adjustment formula should allow a firm to recover an appropriate fraction of all previous flotation expenses.

VII. Conclusion

Having reviewed the literature and analyzed flotation cost issues, I conclude that:

Definition of Flotation Cost: A regulated firm should be allowed to recover both the total underwriting and issuance expenses associated with issuing securities and the cost of market pressure.

Time Pattern of Flotation Cost Recovery. Shareholders are indifferent between the alternatives of immediate recovery of flotation costs and recovery over time, as long as they are fairly compensated for the opportunity cost of their money. This opportunity cost must include both the time value of money and a risk premium for equity investments of this nature.

Regulatory Recovery of Flotation Costs. The Patterson approach to recovering flotation costs is the only rate-of-return-adjustment approach that meets the *Hope* case criterion that a regulated company's revenues must be sufficient to allow the company an opportunity to recover all prudently incurred expenses, including the cost of capital. The

Patterson approach is also the only rate-of-return-adjustment approach that provides an incentive for investors to invest in the regulated company.

<u>Implementation of a Flotation Cost Adjustment</u>. As noted earlier, prevailing regulatory practice seems to be to allow the recovery of flotation costs through an adjustment to the required rate of return. My review of the literature on this subject indicates that there are at least two recommended methods of making this adjustment: the Patterson approach and the Arzac-Marcus approach. The Patterson approach assumes that a firm's flotation expenses on new equity issues are treated in the same manner as flotation expenses on new bond issues, i. e., they are amortized over future time periods. If this assumption is true (and I believe it is), then the flotation cost adjustment should be applied to a firm's entire equity base, including retained earnings. In practical terms, the Patterson approach produces an increase in a firm's cost of equity of approximately thirty basis points. The Arzac-Marcus approach assumes that flotation costs on new equity issues are recovered entirely in the year in which the securities are sold. Under the Arzac-Marcus assumption, a firm should not be allowed any adjustments for flotation costs associated with previous flotations. Instead, a firm should be allowed only an adjustment on future security sales as they occur. Under reasonable assumptions about the rate of new equity sales, this method produces an increase in the cost of equity of approximately six basis points. Since the Arzac-Marcus approach does not allow the company to recover the entire amount of its flotation cost, I recommend that this approach be rejected and the Patterson approach be accepted.

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Table 1

Direct Costs as a Percentage of Gross Proceeds
for Equity (IPOs and SEOs) and Straight and Convertible Bonds
Offered by Domestic Operating Companies 1990—1994[13]

Equities

		IPOs				SEOs			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	337	9.05%	7.91%	16.96%	167	7.72%	5.56%	13.28%
2	10-19.99	389	7.24%	4.39%	11.63%	310	6.23%	2.49%	8.72%
3	20-39.99	533	7.01%	2.69%	9.70%	425	5.60%	1.33%	6.93%
4	40-59.99	215	6.96%	1.76%	8.72%	261	5.05%	0.82%	5.87%
5	60-79.99	79	6.74%	1.46%	8.20%	143	4.57%	0.61%	5.18%
6	80-99.99	51	6.47%	1.44%	7.91%	71	4.25%	0.48%	4.73%
7	100-199.99	106	6.03%	1.03%	7.06%	152	3.85%	0.37%	4.22%
8	200-499.99	47	5.67%	0.86%	6.53%	55	3.26%	0.21%	3.47%
9	500 and up	10	5.21%	0.51%	5.72%	9	3.03%	0.12%	3.15%
10	**Total/Average**	**1,767**	**7.31%**	**3.69%**	**11.00%**	**1,593**	**5.44%**	**1.67%**	**7.11%**

Bonds

		Convertible Bonds				Straight Bonds			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	4	6.07%	2.68%	8.75%	32	2.07%	2.32%	4.39%
2	10-19.99	14	5.48%	3.18%	8.66%	78	1.36%	1.40%	2.76%
3	20-39.99	18	4.16%	1.95%	6.11%	89	1.54%	0.88%	2.42%
4	40-59.99	28	3.26%	1.04%	4.30%	90	0.72%	0.60%	1.32%
5	60-79.99	47	2.64%	0.59%	3.23%	92	1.76%	0.58%	2.34%
6	80-99.99	13	2.43%	0.61%	3.04%	112	1.55%	0.61%	2.16%
7	100-199.99	57	2.34%	0.42%	2.76%	409	1.77%	0.54%	2.31%
8	200-499.99	27	1.99%	0.19%	2.18%	170	1.79%	0.40%	2.19%
9	500 and up	3	2.00%	0.09%	2.09%	20	1.39%	0.25%	1.64%
10	**Total/Average**	**211**	**2.92%**	**0.87%**	**3.79%**	**1,092**	**1.62%**	**0.62%**	**2.24%**

[13] Inmoo Lee, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *Journal of Financial Research* Vol 19 No 1 (Spring 1996) pp. 59-74.