BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR INCREASE IN RATES BY GULF POWER COMPANY.
_______________________________________/

DOCKET NO. 110138-EI

VOLUME 8

Pages 1288 through 1523

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Wednesday, December 14, 2011

TIME: Recommenced at 9:30 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR

APPEARANCES: (As heretofore stated.)

I N D E X

WITNESSES

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PROCEEDINGS

(Transcript continues in sequence from Volume 8.)

CHAIRMAN GRAHAM: Good morning, everyone.

MR. WRIGHT: Good morning.

CHAIRMAN GRAHAM: Let's see if I can't figure out where we left off yesterday. I know staff was going to come back with exhibits, and you guys were working on some stipulations. And I guess I will turn towards Ms. Klancke and find out where we are.

MS. BARRERA: Last night -- good morning, Commissioners.

CHAIRMAN GRAHAM: Good morning.

MS. BARRERA: Good morning, Commissioners. Last night we were about to introduce some exhibits into the record, and we would like to distribute them now. They were exhibits to the deposition.

CHAIRMAN GRAHAM: So we're going to give this one exhibit number and just call it a composite?

MS. BARRERA: Yes, sir.

CHAIRMAN GRAHAM: I believe we're at Number 202.

MS. BARRERA: We're looking.

Yes, it's Number 202. And the exhibits that we're moving are Deposition Exhibit 1, which is, I believe, already in the record, because it's Exhibit MTO-2, Schedule 6.1 to 6.9. Exhibit 2 is Gulf's response to Staff's Fourth Set of Requests for Production, Number 12, which is already on the record. Exhibit 5, which is data used in regression of MDS as presented in Schedule 1. Number 6 is "Final Gulf MDS_6-11 Markup," which is also a document produced by Gulf. Number 10, which is "Charging for Distribution Utility Service: Issues in Rate Design," which is a -- it's a document produced by the Regulatory Assistance Project for NARUC. Exhibit 12, which is pages 15 and 16 of Mr. O'Sheasy's direct testimony in Docket 010949-EI.

CHAIRMAN GRAHAM: Ms. Kaufman.

MS. KAUFMAN: Good morning, Chairman and Commissioners. I think I have some good news, and that is, it's my understanding that of the four exhibits I objected to, Staff has withdrawn their request to enter three of them. The only remaining one I had an objection to is Exhibit Number 10, due to its relevance. But I think that Mr. O'Sheasy spent some time in his deposition explaining why he did not think this document was relevant to the issues, so I will withdraw my objection to Number

10.

CHAIRMAN GRAHAM: Okay. So there's no objections to what we are now calling Exhibit 202, which is a composite of O'Sheasy's exhibits.

MS. BARRERA: Thank you.

CHAIRMAN GRAHAM: I don't see anybody nodding their head no, so we will enter 202 into the record.

(Exhibit Number 202 was marked for identification and admitted into the record.)

MR. GRIFFIN: Mr. Chairman?

CHAIRMAN GRAHAM: Yes.

MR. GRIFFIN: With that, I believe that Mr. O'Sheasy is prepared to be excused from this hearing.

CHAIRMAN GRAHAM: He can go home, yes.

MR. GRIFFIN: Thank you.

CHAIRMAN GRAHAM: Thank you, sir. Travel safe.

MR. STONE: Mr. Chairman, you also alluded to our request at the close of business yesterday for an opportunity to meet, and I will tell you that we had a first such session, that there will need to be more sessions. And we appreciate that opportunity, and we are ready to proceed with the hearing, and we will continue on a simultaneous path, and we may be able to have something to bring back to the Commission shortly.

CHAIRMAN GRAHAM: Okay.

MR. STONE: "Shortly" may be in the eyes of beholder.

CHAIRMAN GRAHAM: All right. So Mr. -- all right. I take it your witness is next.

MR. WRIGHT: Yes, sir. Thank you, Mr. Chairman. The Florida Retail Federation calls Steve W. Chriss.

Thereupon,

STEVE W. CHRISS

was called as a witness on behalf of the Florida Retail Federation, and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WRIGHT:

Q. Good morning, Mr. Chriss.

A. Good morning.

Q. You took the witness's oath yesterday afternoon, did you not?

A. I did.

Q. Okay. You realize you're still under oath for today?

A. Yes.

Q. Are you the same Steve W. Chriss who prepared and caused to be filed in this proceeding prefiled direct testimony consisting of 15 pages?

A. Yes.

Q. Do you have any changes or corrections to that testimony?

A. No.

Q. If I were to ask you the same questions today, would your answers be the same?

A. Yes.

Q. And you do adopt this as your sworn testimony to the Florida Public Service Commission in this docket?

A. Yes.

Q. Did you also prepare and cause to be filed in this proceeding four exhibits numbered in your filing Exhibits SWC-1 through SWC-4?

A. Yes.

Q. Do you have any changes or corrections to make to those exhibits?

A. No.

MR. WRIGHT: Mr. Chairman, as I mentioned early in the morning of day one, apparently inadvertently Mr. Chriss's Exhibit SWC-4 was left off the Composite Exhibit List. His exhibits are presently marked for identification as 26, 27, and 28, and those correspond to SWC-1 through 3. I would ask now that Exhibit SWC-4 also be marked for identification. And in the numeric sequence it would be 203, but if you want to do something different, it's okay with me.

CHAIRMAN GRAHAM: Staff, is there a reason why SWC-4 is not on the list?

MR. YOUNG: I think again this was a clerical oversight.

CHAIRMAN GRAHAM: Okay. We will label SWC-4 as 203.

(Exhibit Number 203 was marked for identification.)

MR. WRIGHT: Thank you, Mr. Chairman.

At this time, I would move that Mr. Chriss's prefiled direct testimony be entered into the record as though read.

CHAIRMAN GRAHAM: We will enter Mr. Chriss's prefiled direct testimony into the record as though read.

MR. WRIGHT: Thank you, Mr. Chairman.

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

A. My name is Steve W. Chriss. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. ("Walmart") as Senior Manager, Energy Regulatory Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Florida Retail Federation ("FRF"), a statewide trade association of more than 9,000 of Florida's retailers, many of whom are retail customers of Gulf Power Company ("Gulf").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Masters of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings, and was promoted to my current position in June 2011. My Witness Qualifications Statement is included herein as Appendix A.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony before utility regulatory commissions in 26 states – Arkansas, Colorado, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, Virginia, Washington, and West Virginia – and before a legislative committee in Missouri. My testimony has addressed topics including cost of service and rate design, ratemaking policy, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits to my testimony:

Exhibit SWC-1: Witness Qualifications Statement

Exhibit SWC-2: "Addressing the Level of Florida's Electricity Prices" by Theodore Kury.

Exhibit SWC-3: Calculation of Gulf Power Commercial Rates, 2006-2010

Exhibit SWC-4: Calculation of Jurisdictional Revenues Collected through Base Rates

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a customer perspective on Gulf's proposed rate increase and to explain the FRF's concerns regarding the Company's return on equity ("ROE"), operations and maintenance ("O&M") expenses, and rate base proposals.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. My recommendations to the Commission are as follows:

1) The Commission should consider the impacts to customers given current economic conditions and the high level of Gulf's current rates.
2) The Commission should reject Gulf's proposed Adjustment 9 because it would allow Gulf to earn a return on a possible future power plant site that is not used and useful in providing service to its customers and that Gulf has no plans to use to serve its customers for at least the next 10 years.
3) The Commission should reject Gulf's request to include $60.9 Million of CWIP in rate base.

The fact that an issue is not addressed should not be construed as an endorsement of any filed position.

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT GULF'S PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are Gulf's residential and small business customers. Given current economic conditions, a rate increase is a serious concern for retailers and their customers and the PSC should consider these impacts thoroughly and carefully in ensuring that any increase in Gulf's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

Q. WHAT REVENUE REQUIREMENT INCREASE HAS THE COMPANY PROPOSED IN ITS FILING?

A. The Company has proposed a total base rate revenue requirement increase of $93.5 million. *See* MFR Schedule A-1. This is a significant increase, especially when increases in Gulf's rates in recent years, particularly for commercial customers, are taken into consideration.

Q. HAS THE COMMISSION RECENTLY RELEASED A UNIVERSITY OF FLORIDA REPORT REGARDING THE ELECTRIC RATES OF FLORIDA UTILITIES RELATIVE TO OTHER SOUTHEASTERN STATES?

A. Yes. The Commission has released on its website the September 28th, 2011 University of Florida report titled "Addressing the Level of Florida's Electricity Prices." *See* Exhibit SWC-2.

Q. WHAT ARE THE REPORT'S FINDINGS FOR COMMERCIAL CUSTOMERS' ELECTRIC RATES?

A. The report finds that Florida's electric rates for commercial customers have increased steadily from 2000 through 2008 and, as of 2008, the last year in the study period, Florida's electric rates for commercial customers were among the highest in the Southeastern United States. *Id.*, page 4.

Q. DOES A REVIEW OF GULF POWER'S RATES FOR COMMERCIAL CUSTOMERS REFLECT THE GENERAL TRENDS PRESENTED IN THE REPORT?

A. Yes. A review of Gulf's FERC Form 1 filings for years 2006 through 2010 shows that the Company's rates for the total body of commercial customers have increased from about 7.6 cents/kWh in 2006 to about 10.9 cents/kwh in 2010, an increase of over 43 percent. This constitutes a $143 million increase in annual revenue collections from commercial customers between 2006 and 2011. *See* Exhibit SWC-3. Additionally, and consistent with these data, data reported in the Commission's annual

Statistics of the Florida Electric Utility Industry reports show that Gulf's average revenue per kWh, for all customer classes, increased from about 7.9 cents/kWh in 2006 to about 11.3 cents/kWh in 2010. *See* Florida Public Service Commission, Statistics of the Florida Electric Utility Industry 2006, pages 35 & 38 (Tables 26 & 29); 2010 Statistics of the Florida Electric Utility Industry, pages 35 & 38 (Tables 26 & 29).

Q. DOES YOUR CALCULATION OF A 43 PERCENT INCREASE IN COMMERCIAL RATES INCLUDE AN INCREASE IN GULF'S BASE RATES?

A. No. Gulf has not had a base rate increase since June 7, 2002. *See* Direct Testimony of R. Scott Teel, page 4, line 10.

Q. SHOULD THE COMMISSION CONSIDER THESE FACTORS WHEN IT EXAMINES GULF'S FILING?

A. Yes. The Commission should consider the impacts to customers given current economic conditions and the high level of Gulf's current rates. FRF recognizes Gulf's duty to provide reliable and adequate service to its customers and that there are costs required to do so, including a reasonable return on the Company's used and useful capital investment. However, the Commission needs to ensure that service is provided at the lowest possible cost.

Return on Equity Concerns

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company is proposing an after-tax ROE of 11.7 percent. *See* Direct Testimony of James H. Vander Weide, page 7, line 2 to line 6. Applying the Company's proposed Net Operating Income multiplier (1.634607, from MFR A-1) to this return indicates that Gulf is requesting a before-tax ROE of 19.1 percent.

Q. IS FRF CONCERNED THAT THE PROPOSED ROE IS EXCESSIVE?

A. Yes. FRF is concerned that the Company's proposed ROE is excessive, especially given the current economic conditions faced by the utility's customers as well as when viewed in light of the Company's low percentage of jurisdictional revenues collected through base rates and the high percentage of the Company's costs that are recovered through cost recovery clause charges, such as Fuel and Purchased Power Cost Recovery, Capacity Cost Recovery, Environmental Cost Recovery, and Energy Conservation Cost Recovery. Additionally, since its last base rate case, Gulf has been allowed to use storm cost recovery charges to recover storm restoration costs that Gulf experienced due to Hurricanes Katrina, Dennis, and Ivan. *See* PSC Order No. PSC-05-0250-PAA-EI, in Docket No. 050093-EI; PSC Order No. 06-0601-S-EI, in Docket No. 060154-EI.

Q. FOR THE COMPANY'S PROPOSED 2012 TEST YEAR, WHAT PERCENT OF JURISDICTIONAL REVENUES ARE PROPOSED TO BE COLLECTED THROUGH BASE RATES?

A. Approximately 34 percent of jurisdictional revenues for the proposed 2012 test year would be collected through base rates and would be essentially at risk due to regulatory lag. This low percentage of Gulf's total revenues recovered through base rates mirrors the corresponding high percentage of its total revenues that Gulf recovers through cost recovery clause charges and other line-item charges. *See* Exhibit SWC-4.

Q. ARE THERE ANY OTHER FACETS OF THE COMPANY'S PROPOSAL IN THIS DOCKET THAT COULD IMPACT GULF'S EXPOSURE TO REGULATORY LAG?

A. Yes. The use of a projected test year reduces the risk due to regulatory lag because, as the Commission pointed out in the last Gulf rate case order, "the main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect." *See* Order No. PSC-02-0787-FOF-EI, page 9. As such, the Commission should carefully consider the level of ROE justified by the Company's exposure to regulatory lag.

O&M Concerns

Q. WHAT LEVEL OF O&M COSTS DOES THE COMPANY PROPOSE TO INCLUDE IN RATES?

A. The Company proposes to include approximately $288 million in O&M costs in rates. *See* Direct Testimony of Richard J. McMillan, page 23, line 6 to line 7.

Q. DOES FRF HAVE A CONCERN WITH THE PROPOSED LEVEL OF O&M COSTS?

A. Yes. The proposed level of O&M costs exceeds the Commission's O&M Benchmark level by approximately $38 million. *Id.* To put this in perspective, the difference between Gulf's requested allowance for O&M costs and the Commission's O&M benchmarks is equal to more than 40 percent of Gulf's total requested increase. Additionally, the proposed level exceeds the 2010 historical O&M costs by approximately $50 million, an increase of approximately 21 percent. *See* MFR Schedule C-1, page 3.

Q. WHY IS THIS A CONCERN?

This is a concern for two reasons. First, the proposed O&M costs are a concern because of the significant increase in those costs proposed by the Company. Second, the Commission's benchmark can serve essentially as an *ex ante* budget level, as the Company has before-the-fact knowledge of what the O&M Benchmark value will be, but the Company has chosen not to use the O&M Benchmark in its budgeting process. *See* Direct Testimony of Constance J. Erickson, page 7, line 16 to line 17. As such, the Commission should carefully consider the appropriate level of O&M costs to be included in rates.

Rate Base Concerns

Q. DOES THE COMPANY PROPOSE TO INCLUDE IN RATE BASE LAND AND OTHER DEFERRED CHARGES RELATED TO THE COMPANY'S NUCLEAR SITE SELECTION COSTS?

A. Yes. The Company proposes Adjustment 9, which would include approximately $27 million in rate base for the land and other deferred nuclear site selection costs. The revenue effect of this addition, as plant held for future use, is just over $3 million. *See* Direct Testimony of Richard J. McMillan, page 5, line 9 to line 11 and Exhibit RJM-1, Schedule 2, page 2.

Q. UNDER WHAT AUTHORITY DOES THE COMPANY REQUEST INCLUSION OF THESE COSTS IN RATE BASE?

A. This is not clear from Gulf's testimony, although Company witness McMillan states that "Gulf relied on the recovery provided by" Florida Statute 366.93. *Id.*, line 11 to line 13.

Q. DOES THE COMPANY SPECIFY THAT THE LAND WOULD BE USED ONLY FOR NUCLEAR OR INTEGRATED GASIFICATION COMBINED CYCLE POWER PLANTS?

A. No. The Company states that the site will be available for "any future nuclear or non-nuclear generation needs" and has "all the attributes – water, rail, and gas – necessary for other forms of generation." *Id.,* line 22 to page 6, line 2.

Q. HAS THE COMPANY INDICATED THAT, FOR THE SITE IN QUESTION, IT HAS RECEIVED A FINAL ORDER FROM THE COMMISSION GRANTING A DETERMINATION OF NEED FOR A POWER PLANT?

A. No. The Company's witnesses do not indicate that the Company has received a final order from the Commission granting a determination of need for a power plant on the site in question.

Q. IS FRF CONCERNED WITH THIS PROPOSAL?

A. Yes. FRF is concerned for two reasons. First, Gulf states that it "relied on" the nuclear advance cost recovery statute, Florida Statute 366.93, but without a determination of need and Gulf's option to use it for an unspecified generation technology, in my opinion though I am not an attorney, it is not clear that Gulf has followed the statute. It is inconsistent for Gulf to claim that it relied on Florida Statute 366.93 and then try to seek recovery without showing that they have followed that statute.

Second, Gulf is proposing to include $27.687 million in plant held for future use for costs for a potential power plant site that, as I will explain below, Gulf will not use before 2022 – eleven years from now – and potentially may not use at all.

Q. HAS THE COMPANY GIVEN ANY PUBLIC INDICATION OF ITS PLANS FOR THIS SITE?

A. Not specifically, however in its 2011-2020 Ten Year Site Plan for Electric Generating Facilities and Associated Transmission Lines, Gulf has stated that it has no plans to add any generating capacity until after 2020, so it can be inferred that as such the Company does not plan to use the site for generation until at least 2020, as their next need for capacity does not begin to develop until 2022. Additionally, when that need does begin to develop, Gulf will consider four other existing Gulf sites as the location for such future capacity: "its existing Florida sites at Plant Crist in Escambia County, Plant Smith in Bay County, and Plant Scholz in Jackson County, as well as its greenfield Florida site at Shoal River in Walton County." *See* Gulf Power's Ten Year Site Plan, April 1, 2011, Docket 110000, page 68.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. Given the above circumstances, the Commission should reject Gulf's proposed Adjustment 9 because it would allow Gulf to earn a return on a possible future power plant site that is not used and useful in providing service to its customers and that Gulf has no plans to use to serve its customers for at least the next 10 years.

Q. DOES THE COMPANY PROPOSE TO INCLUDE CONSTRUCTION WORK IN PROGRESS ("CWIP") IN ITS RATE BASE?

A. Yes. The Company has proposed to include approximately $60.9 million of CWIP in rate base. *See* MFR Schedule B-1, page 1. This is an increase of approximately $12.5 million from the actual CWIP in rate base for 2010. *See* MFR Schedule B-1, page 3.

Q. IS THE INCLUSION OF CWIP IN RATE BASE OF CONCERN TO FRF?

A. Yes. The inclusion of CWIP in rate base charges ratepayers for assets that are not yet used and useful in the provision of electric service. Under the Company's proposal ratepayers would pay for the assets during a period when they are not receiving benefits from those assets, so the matching principle (*i.e.* customers bearing costs only when they are receiving a benefit) is not satisfied. In this case, Gulf's customers in 2012, the test year that the Company chose for its rate increase request, would pay for assets that do not provide service – i.e., assets that are not used and useful – during that test year. The problem is compounded by changes in the number of customers during the construction process. For example, customers may pay for the assets during construction but leave the system before they are operational, receiving no benefit from the assets for which they helped pay.

Q. IS THERE ANOTHER CONCERN WITH THE INCLUSION OF CWIP IN RATE BASE THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. Including CWIP in rate base shifts the risks traditionally assumed by investors, for which they are compensated through the rate of return elements once the plant is in service, and instead places the risks squarely on the shoulders of ratepayers with no offer of compensation. Additionally, should the Company encounter problems during construction of the plant resulting in stoppage of the construction, non-completion of the project and/or substantial delay in the completion of the project, consumers have no recourse for recovering the money they have paid for the inclusion of CWIP in rate base.

Q. WHAT IS YOUR UNDERSTANDING OF HOW, UNDER TRADITIONAL REGULATORY PRACTICES, GULF WOULD RECOVER THE COSTS OF THE ASSETS THAT WILL, ACCORDING TO GULF, BE UNDER CONSTRUCTION BUT NOT COMPLETED DURING THE COMPANY'S CHOSEN TEST YEAR?

A. Under traditional regulatory practices, Gulf would add the assets to its rate base accounts if and when they were completed. They would then be reflected in the rate base and depreciation accounts in Gulf's earnings surveillance reports and would, other things equal, lower Gulf's achieved ROE. If and when Gulf's earnings (i.e., its ROE) were to fall to a level that Gulf believed was insufficient to enable it to provide adequate and reliable service, Gulf could ask for a rate increase that would include the value of the assets in some future test year.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. The Commission should reject Gulf's request to include $60.9 Million of CWIP in rate base.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. WRIGHT:

Q. Mr. Chriss, would you please summarize your testimony for the Commission.

A. Yes, sir. Good morning, Chairman Graham and Commissioners. My name Steve Chriss, and I am Senior Manager, Energy Regulatory Analysis, for Walmart Stores, Inc. I'm here today to testify on behalf of the Florida Retail Federation, a statewide trade association of more than 9,000 of Florida's retailers, many of whom are retail customers of Gulf Power. In my direct testimony I put forth three recommendations:

First, the Commission should consider the impacts of a Gulf Power rate increase to customers given current economic conditions and the high level of Gulf's current rates. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in costs to retailers puts pressure on consumer prices and on other expenses required by a business to operate. Rate increases also impact retailers' customers who are Gulf's residential and small business customers.

Given current economic conditions, a rate increase is a serious concern for retailers and their customers, and the PSC should consider these impacts thoroughly and carefully in ensuring that any increase in Gulf's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

A review of Gulf's FERC Form 1 filings for 2006 through 2010 shows that the company's rates for commercial customers have increased over 43 percent during that period, a period in which Gulf did not file for or receive a base rate increase. In my testimony, I discuss the FRF's concerns with the company's proposed return on equity, given that the company collects approximately 34 percent of its jurisdictional revenues through base rates and that the use of a projected test year reduces risks associated with regulatory lag. I also discuss the FRF's concerns regarding the level of O&M costs proposed to be included in rates.

My second recommendation is that the Commission should reject Gulf's proposed Adjustment 9, as it would allow Gulf to earn a return on a possible future plant site that is not used and useful in providing service and that Gulf has no plans to use to serve its customers for at least the next 10 years.

Finally, I recommend the Commission should reject Gulf's request to include $60.9 million of construction work in progress in rate base. The inclusion of CWIP in rate base charges ratepayers for an asset that is not used and useful in the provision of electric service, so those ratepayers paying for the asset receive no benefit from that asset.

This concludes my summary. Thank you.

MR. WRIGHT: Thank you, Mr. Chriss, and thank you, Mr. Chairman. Mr. Chriss is tendered for cross-examination.

CHAIRMAN GRAHAM: Is there any -- of course, we said there's no friendly cross, but is there any intervenors that's position is contrary to the one of FRF on this issue?

MR. McGLOTHLIN: OPC has no questions.

MS. KAUFMAN: FIPUG has no questions.

MAJOR THOMPSON: No questions.

CHAIRMAN GRAHAM: Okay. That brings us to Gulf.

MR. MELSON: Mr. Chairman, we're going to make a request here that will apply to the other witnesses as well. We would ask permission to cross-examine after Staff. We had agreed originally if these witnesses did not take the stand that we're willing to -- would be willing to waive cross-examination.

We're essentially willing to waive cross-examination still except on matters that might get brought up during Staff's questioning.

Since we've got the burden of proof, we would like to hear if the Staff has questions. And if we had any follow-up cross-examination, it would be only on matters that came out during Staff's questions.

CHAIRMAN GRAHAM: If you're going to limit it to just matters addressing Staff's questions --

MR. MELSON: Yes, sir.

CHAIRMAN GRAHAM: I think that's reasonable.

MR. McGLOTHLIN: Mr. Chairman, I would just like to point out that the other parties are in the same position in case after case. We cross and the Staff goes last. I can't remember any special dispensation for any of the intervenors. If Gulf Power wants that privilege, we want the same privilege.

CHAIRMAN GRAHAM: I don't have a problem doing that, but that just means you're going to limit it only to the questions that Staff asks, and if Staff doesn't ask any questions, then you won't be asking any questions. If you're willing to submit yourself to that, I don't have a problem with granting that. I think that moves the process along.

MS. KAUFMAN: That process is acceptable to FIPUG.

CHAIRMAN GRAHAM: Okay. Staff?

MS. KLANCKE: Staff has no questions for this witness.

CHAIRMAN GRAHAM: Board? Okay. There's no redirect.

MR. WRIGHT: No, sir.

CHAIRMAN GRAHAM: Next witness.

MR. WRIGHT: So may Mr. Chriss be excused?

CHAIRMAN GRAHAM: Yes, he can.

MR. WRIGHT: Thank you, Mr. Chairman.

THE WITNESS: Thank you.

MR. WRIGHT: Mr. Chairman, I would move at this time Exhibits 26, 27, 28, and 203.

CHAIRMAN GRAHAM: We'll move 26, 27, and 28 on page 9, and 203 into the record.

(Exhibit Numbers 26, 27, 28, and 203 were admitted into the record.)

MR. WRIGHT: Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Thank you. Next we have Mr. Gorman.

MAJOR THOMPSON: Mr. Chairman, he hasn't been sworn in yet.

CHAIRMAN GRAHAM: Hold on just a second. We need to put in FIPUG's Mr. Pollock. I believe that one was stipulated. We need to make sure that his exhibits and everything is put into the record.

MS. KAUFMAN: Yes. We would move the testimony of Mr. Pollock, and he had an errata sheet that has been filed. And he also has Exhibits 29 through 34 that I would move.

CHAIRMAN GRAHAM: We'll move Exhibits 29, 30, and 31 into the record, and 32, 33, and 34 into the record.

(Exhibit Numbers 29 through 34 were admitted into the record.)

MS. KAUFMAN: And I don't recall, but if his testimony has not been moved into the record yet, we would so move it.

CHAIRMAN GRAHAM: I can't remember if we did or not. We will move his prefiled direct testimony into the record as though read.

MS. KAUFMAN: Thank you.

1. INTRODUCTION, QUALIFICATIONS, AND SUMMARY

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock; 12655 Olive Blvd., Suite 335, St. Louis, MO 63141.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and President of J. Pollock, Incorporated.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in regulatory matters before this Commission since 1976. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** to this testimony.

Q **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). Participating FIPUG companies purchase electricity from Gulf Power Company (Gulf). These customers require a reliable low-cost supply of electricity to power their operations. Therefore, participating FIPUG companies have a direct and significant interest in the outcome of this proceeding.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A I will address the following issues:

- The need for this Commission to thoroughly scrub Gulf's claimed revenue requirements in light of the fact that Gulf's industrial rates are among the highest in the southeast and because of the current depressed state of the economy in Gulf's service territory;
- The class cost-of-service study (CCOSS), and in particular Gulf's proposed classification of distribution network costs; and
- Gulf's proposal to increase its storm damage accrual.

Q ARE YOU FILING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A Yes. I am filing **Exhibits JP-1** through **JP-6**. These exhibits were prepared by me or under my direction and supervision.

Q ARE YOU TAKING A POSITION ON ALL ISSUES RAISED BY GULF IN THIS CASE?

A No. The fact that I do not address a particular issue in my testimony should not be interpreted as an endorsement of Gulf's position on a particular issue.

Summary

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A In light of the high unemployment in Gulf's service area and the fact that Gulf's industrial electricity rates have increased significantly and are now among the most expensive in the southeast, the Commission should thoroughly scrub the filing to minimize the impact of this proceeding on all customers.

Gulf's CCOSS generally comports with and uses accepted cost allocation practices. This includes the proposal to classify a portion of the distribution network (FERC Account Nos. 364 through 368) as customer-related. Classifying a portion of the distribution network as customer related appropriately recognizes that costs are incurred to connect a customer to the grid, irrespective of the amount of electricity consumed. The costs are incurred, in part, to comply with this Commission's rules prescribing that each utility meet certain minimum construction standards and to implement cost-effective storm hardening investments on the transmission and distribution system. Because these "compliance" costs must be incurred regardless of the amount of electricity consumed, they are clearly customer-related.

The Commission should reject Gulf's proposal to nearly double the annual storm accrual because it ignores this Commission's framework that provides for recovery of all restoration costs for the most severe storms. Gulf's current storm reserve balance is sufficient to cover the costs of all but the most severe storms. Further, continuing the current level of accruals will more than cover the average level of expenses charged to the storm reserve since 2005.

2. THE IMPACT OF THIS CASE

Q WHAT BASE REVENUE INCREASE IS GULF SEEKING IN THIS PROCEEDING?

A Gulf is seeking a $93.5 million (20.8%) base revenue increase. This proposal is based on a calendar year 2012 test year and assumes an 11.7% return on common equity (ROE).

Q WHEN WERE GULF'S CURRENT BASE RATES SET?

A Gulf's current base rates were implemented in June 2002, following the Commission's final order in Docket No. 010949-EI.

Q DOES THIS MEAN THAT GULF'S CUSTOMERS HAVE NOT EXPERIENCED HIGHER ELECTRICITY COSTS SINCE JUNE 2002?

A No. While Gulf touts that it has not had a base rate increase in many years, Gulf has continued to increase rates through changes in its various cost recovery factors. Gulf's cost recovery factors include:

- Fuel Charge;
- Conservation Charge;
- Capacity Charge; and
- Environmental Charge.

These factors apply to all customers and comprise 65% of the revenues Gulf recovers from retail customers. That is, the amount Gulf collects from customers through separate recovery clauses (outside of base rate cases) comprises 65% of Gulf's revenues. Thus, no customer has been immune from higher electricity costs. This includes Gulf's real-time pricing (RTP) customers whose base rates have also been affected by changes in incremental costs in addition to the increase in the cost recovery factors listed above.

Q **HAVE YOU ANALYZED THE INCREASE IN ELECTRICITY COSTS EXPERIENCED BY GULF'S CUSTOMERS SINCE JUNE 2002?**

A Yes. **Exhibit JP-1** compares the increase in electricity costs experienced by residential, commercial and industrial customers since June 2002. Thus, it provides a range of impacts from smaller low-load factor customers to larger high-load factor customers. The comparison includes both base rates and the then-applicable cost recovery factors.

Despite the fact that Gulf's base rates have not changed, all customers have experienced significant increases in electricity costs. Such increases range from 57% to 115%. Under Gulf's proposed base rates, the cumulative increases would range from 68% to 124%. Higher load factor (Rate LPT and Rate PX) customers have experienced (and will experience) much larger increases in electricity costs than lower load factor customers.

Q **ARE GULF'S INDUSTRIAL ELECTRIC RATES COMPETITIVE?**

A No. As a consequence of the increasing cost recovery factors, Gulf's industrial rates now rank among the highest of any major investor-owned electric utility in the southeast United States. This is shown in **Exhibit JP-2**, which consists of recent surveys of the electricity rates charged by thirty investor-owned electric utilities and the Tennessee Valley Authority (TVA) applicable to large high-load factor customers taking transmission service under standard firm tariffs. The surveys were conducted by Brubaker & Associates, Inc. (BAI). For the four most recent BAI surveys, Gulf's industrial rates have ranked among the top three highest of the 31 southeast utilities.

Q WHAT ARE THE IMPLICATIONS OF GULF'S HIGH INDUSTRIAL ELECTRICITY RATES?

A Electricity is a significant operating cost for manufacturers and other industrial consumers. High electricity rates make it very difficult for these entities to compete in both domestic and global markets where electricity rates may be much lower. Gulf's request for an increase of over $90 million does not bode well for preserving or growing the jobs these companies create in Gulf's service area.

Q ARE YOU AWARE THAT GOVERNOR RICK SCOTT HAS MADE IT A TOP PRIORITY OF HIS ADMINISTRATION TO CREATE AN ADDITIONAL 700,000 PRIVATE SECTOR JOBS IN FLORIDA OVER THE NEXT SEVEN YEARS?

A Yes, that is my understanding.

Q HOW WILL GULF'S CURRENT RATES FOR MANUFACTURERS AND INDUSTRIAL CONSUMERS, WHEN COMBINED WITH GULF'S REQUEST FOR MORE THAN $90 MILLION IN NEW BASE RATES, AFFECT THE ABILITY TO ATTRACT NEW PRIVATE SECTOR JOBS TO NORTHWEST FLORIDA AND GULF'S SERVICE TERRITORY?

A As I point out, currently Gulf's electric rates for large industrial consumers are among the highest in the southeastern United States. Gulf's request to increase base rates by over $90 million will make northwest Florida less attractive when competing to convince new industrial and commercial businesses to locate in Gulf's service territory. The cost of electricity is often a significant variable cost for business. As businesses are always sensitive to costs, especially in these difficult economic times, neighboring states with significantly lower electricity costs will have an advantage in energy costs when competing against Florida to recruit new business and the new private sector jobs that come with new businesses. Granting Gulf's requested rate hike will only increase and exacerbate the disparity between what utilities in neighboring states charge industrial customers as compared to what those same customers are charged for the same commodity, electricity, in Florida when doing business in Gulf's service territory in northwest Florida.

Q WHAT IS THE STATE OF THE LOCAL ECONOMY IN GULF'S SERVICE AREA?

A The local economy in Gulf's service territory continues to be depressed. **Exhibit JP-3** shows a weighted average of the unemployment rate in Gulf's service area:

- In 2002, following Gulf's last rate case;
- In 2009, at the height of the recession; and
- Currently.

As **Exhibit JP-3** shows, the unemployment rate increased from 5.1% in 2002 to 8.5% in 2009. Despite the official end of the recession, the unemployment rate has risen, and it is now 9.4%. The Florida average unemployment rate has also increased. Currently, the unemployment rates in both Gulf's service area and the state of Florida are higher than the national average.

Q WHAT ARE THE IMPLICATIONS OF GULF'S HIGH INDUSTRIAL ELECTRICITY RATES AND THE CURRENTLY DEPRESSED LOCAL ECONOMY?

A High industrial electricity rates play a major role in decisions by large energy-intensive consumers about where to locate, where it is more cost-effective to operate, and whether to expand production, furlough employees or even cease operations. As Florida attempts to encourage economic development and create new jobs, the Commission must ensure that Gulf's request for a rate increase minimizes the impact on all customers.

3. CLASS COST-OF-SERVICE STUDY

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A cost-of-service study is an analysis used to determine each class' responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the cost of service for that class. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used in a cost-of-service study are described in more detail in **Appendix C**.

Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY GULF POWER COMPANY FILED IN THIS PROCEEDING?

A Yes.

Q DOES GULF'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?

A Yes. Gulf's CCOSS generally recognizes the different types of costs as well as the different ways electricity is used by various customers. In particular, Gulf properly recognizes that a certain portion of the distribution network is customer-related; that is, some distribution investment is required just to connect customers to the grid, irrespective of the level of power and/or energy usage.

Classification of Distribution Network Costs

Q HOW HAS GULF CLASSIFIED DISTRIBUTION INVESTMENT?

A Gulf has classified a portion of its distribution network investment as customer-related. This is consistent with the purpose of the distribution system, which is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (*e.g.,* meters, service drops) must be made just to attach a customer to the system. These investments are customer-related.

Q ARE CERTAIN DISTRIBUTION INVESTMENTS, OTHER THAN THE METER AND SERVICE DROPS, ALSO CUSTOMER-RELATED?

A Yes. A portion of the primary and secondary distribution "network"—consisting of poles, towers, fixtures, overhead lines and line transformers booked to FERC Accounts 364, 365, 366, 367, and 368—is also customer-related. Classifying a portion of the distribution network as customer-related recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

If Gulf were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of line because it is currently required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced.

Q **DO ANY OTHER FACTORS JUSTIFY CLASSIFYING A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. The distribution network must comply with this Commission's standards of construction. Specifically, Rule 25-6.034 requires that:

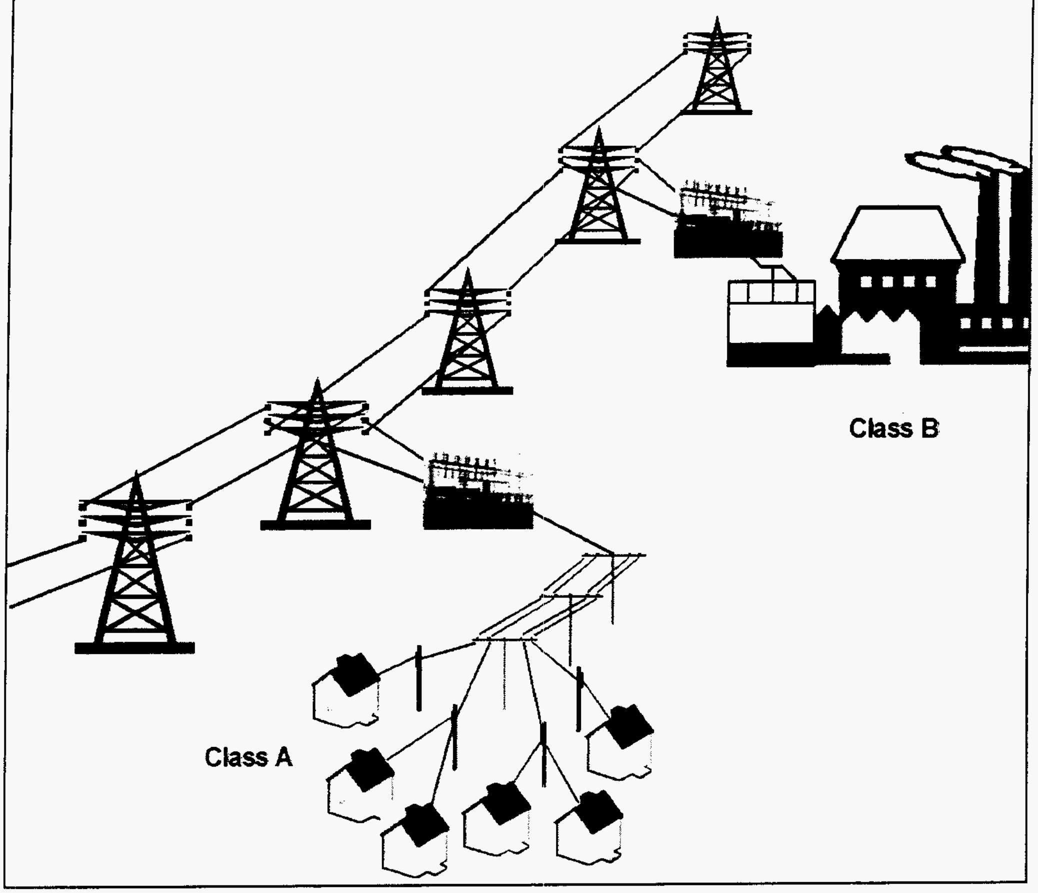
> (1) The facilities of each utility shall be constructed, installed, maintained and operated in accordance with generally accepted engineering practices to assure, as far as is reasonably possible, continuity of service and uniformity in the quality of service furnished.
>
> (2) Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2) [NESC], incorporated by reference in Rule 25-6.0345, F.A.C.

Rule 25-6.0342, Florida Administrative Code, was more recently added. It requires utilities to cost-effectively strengthen critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions. The costs to comply with this Commission's rules are required not because of the amount of electric power and energy demanded but because of the existence of each customer and Gulf's obligation to provide a reliable connection to the grid.

Q **HOW SHOULD THE CUSTOMER-RELATED PORTION OF THIS INVESTMENT BE DETERMINED?**

A This requires an engineering analysis, such as the analysis Gulf provided in this case. The customer-related portion is representative of the investment required simply to attach customers to the system, irrespective of their demand and energy requirements. Consider the diagram below.

Illustration Showing the Customer Component of Distribution Primary and Secondary Plant



This shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q **IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. For example, the NARUC Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. (*NARUC, Electric Cost Allocation Manual at 90).*

An excerpt from the manual pertaining to distribution cost classification is provided in **Exhibit JP-4**.

Q **IS THIS PRACTICE FOLLOWED BY OTHER UTILITIES?**

A Yes. **Exhibit JP-5** is a partial list of the utilities that classify some portion of their distribution network investment as customer-related. This is not intended to be an exhaustive survey.

Q **WHAT PORTION OF THE DISTRIBUTION NETWORK IS GULF PROPOSING TO CLASSIFY AS CUSTOMER-RELATED?**

A Gulf's engineering study resulted in classifying about 27% of its distribution network investment (FERC Accounts 364 through 368) as customer-related. This is shown in **Exhibit JP-5**, line 5, column 6.

Q **DO GULF'S SISTER OPERATING COMPANIES ALSO CLASSIFY SOME PORTION OF THEIR DISTRIBUTION NETWORKS AS CUSTOMER-RELATED?**

A Yes. As can be seen in **Exhibit JP-5**, Alabama Power, Georgia Power, and Mississippi Power also classify a significant portion of their investments in FERC

Accounts 364 through 368 as customer-related. Thus, this practice is widely used, and has been accepted, throughout the Southern Company system.

Q **HOW DOES GULF'S CLASSIFICATION OF DISTRIBUTION NETWORK COSTS COMPARE WITH THE UTILITIES SHOWN IN EXHIBIT JP-5?**

A As previously stated, Gulf classifies about 27% of the investment in FERC Accounts 364 through 368 as customer-related. The corresponding composite percentage for the other listed utilities ranges from 19% to 69%. Some variation is to be expected because of differences between each utility's distribution construction practices and the methodologies used to determine the customer-related component.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A Gulf's proposed classification of distribution network costs comports with accepted practice and is modest relative to other utilities. Accordingly, Gulf's proposed distribution customer classification should be adopted in this case.

4. STORM RESERVE

Q **WHAT IS A STORM RESERVE?**

A Rule 25-6.0143, Florida Administrative Code, states: "A separate subaccount shall be established for that portion of Account No. 228.1 which is designated to cover storm-related damages to the utility's own property or property leased from others that is not covered by insurance."

Q **WHAT IS GULF'S CURRENT STORM RESERVE LEVEL?**

A The balance in Gulf's storm reserve as of December 31, 2010 was $27.6 million. Considering the current annual storm damage accrual of $3.5 million, the balance will grow to $31.1 million assuming no property damage is charged to the reserve in 2011. (*Direct Testimony of Constance Erickson* at 29).

Q **HOW IS THE STORM RESERVE FUNDED?**

A The storm reserve is funded through customer contributions that the Commission authorizes when it sets base rates. Customers currently contribute $3.5 million per year to the storm reserve. At times, it has also been funded through specific surcharges. For example, the Commission approved and Gulf implemented a surcharge over 51 months to recover the costs of Category 3 storms Hurricane Ivan and Hurricane Dennis, which occurred in 2004 and 2005.

Q DOES THE COMMISSION HAVE A FRAMEWORK FOR STORM RESTORATION COST RECOVERY?

A Yes. According to the order in the last Tampa Electric Company rate case, the Commission addresses the storm restoration cost issue in the following manner:

> We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve. (*In re Tampa Electric Company*, FPSC Order No. PSC-09-0283-FOF-EI at 17).

Q WHO ULTIMATELY ASSUMES THE RISK OF LOSS FROM STORM DAMAGE UNDER THE EXISTING COMMISSION FRAMEWORK?

A As the Commission stated, Gulf's customers ultimately bear all of the risk of losses due to hurricanes and other storms:

> . . . under the current approach to the recovery of storm restoration costs, the risk associated with a lower reserve level (i.e., the possibility of storm restoration costs exceeding the Reserve, leading to subsequent customer charges) and the risk associated with a higher reserve level (i.e., paying charges now for storm restoration costs that do not materialize) is completely borne by FPL's customers. The customers represented in this proceeding have made clear that they would rather pay to fund the Reserve to a lower level now and risk future rate volatility than pay to fund the Reserve to a higher level before future storm restoration costs have been incurred. (*In re Florida Power & Light Company,* FPSC Order No. PSC-06-0464-FOF-EI at 25).

As such, Gulf is at little or no risk for recovering storm restoration costs regardless of the amount in the storm reserve. Put simply, from a customer perspective, the question is when to pay for the cost of restoration – before or after the damage occurs. It is clear that customers prefer to pay when the damage occurs, rather than have the utility hold their money for them. And, the

Commission has made it clear through its past actions that when a documented case for such recovery is made, it will permit the utility to recover these costs.

Q **IS GULF PROPOSING AN INCREASE IN THE ANNUAL ACCRUALS FOR ITS STORM RESERVE?**

A Yes. Gulf proposes to nearly double the amount it collects for storm reserve. Specifically, it seeks a $3.3 million increase in annual storm reserve contributions. This would raise the current annual accrual from $3.5 million to $6.8 million per year. This is a significant increase given that Gulf currently has a $27.6 million storm reserve.

Q **HAS GULF SOUGHT TO ESTABLISH A TARGET RESERVE BALANCE?**

A Yes. The current target level is $25.1 million to $36 million, approved by the Commission in Docket No. 951433-EI, Order No. PSC-96-1334-FOF-EI and affirmed in Gulf's last rate case. In this case, Gulf is proposing higher annual accruals with a targeted reserve balance between $52 and $98 million. (*Direct Testimony of Constance Erickson* at 32).

Q **SHOULD GULF'S PROPOSED $3.3 MILLION ANNUAL INCREASE IN STORM RESERVE ACCRUALS BE APPROVED?**

A No. Gulf has not supported the need for a $3.3 million increase. Further, since the current $27.6 million storm reserve is sufficient to cover all but the most severe storms, the annual accrual should not be changed. Put simply, this increase is not warranted, especially given the difficult economic circumstances in Gulf's service territory. As explained below, funds in the storm reserve are sufficient even if the accrual is stopped altogether. Therefore, I recommend that the Commission maintain the accrual at its current level.

Q **WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

A Under the Commission's framework described above, the storm reserve accrual and reserve balance are designed to provide coverage for some, but not all, storms. However, the Expected Annual Damage (EAD) presented by Gulf witness Erickson takes into account all manner and strength of storms. (*Gulf Response to Citizens' Interrogatories, Set 4, No. 206).* In other words, it assumes that the storm reserve should be adequate to cover damage from all storms, even the worst. The current $27.6 million reserve balance covers all Category 1 hurricanes and the majority of, but not the most destructive, Category 2 storms. Thus, it is sufficient to cover four consecutive years in which the expected annual loss chargeable to the storm reserve occurs.

Q **WHY IS GULF SEEKING A $3.3 MILLION INCREASE IN STORM DAMAGE ACCRUALS?**

A The proposed increase is based on the "expected average annual storm loss to be charged to the reserve" derived in the Gulf 2011 Hurricane Loss and Reserve Performance Analysis. (*Direct Testimony of Constance Erickson* at 29).

Q **DOES THE EAD PRESENTED IN THE STUDY PROPERLY REFLECT THE ANNUAL COSTS THAT ARE COVERED WITH THE STORM RESERVE?**

A No. I believe the EAD is overstated because it ignores the Commission's directive that the storm reserve should be adequate to accommodate most, but not all storm years.

Q WHAT TYPE OF STORMS ARE INCLUDED IN THE STUDY PRESENTED BY MS. ERICKSON?

A The EAD is the average damage of thousands of simulated hurricane seasons in the EQECAT model. The EAD of $8.3 million presented by Gulf represents the average of all these simulations. The analysis includes all storm categories in the EAD. The EAD for all levels of storms is $8.3 million per year, with a $6.8 million average expected charge to the reserve. Over the last five and one half years, Gulf has charged $5.3 million (in total) to the reserve, as shown in **Exhibit JP-6**. This equates to an annual average charge to the reserve of less than $1 million.

Q IS THERE ANY OTHER ISSUE WITH HOW THE EAD WAS CALCULATED?

A Yes. Gulf has indicated that the EAD calculation did not include consideration for storm hardening since no major storm has occurred since the storm hardening program was implemented in 2007. (*Gulf's response to Citizens Interrogatory Set 4, No. 205*). One would expect the expenditures dedicated to this program to reduce storm damage. However, the EAD calculation omits these benefits.

Q WHAT IS THE LIKELIHOOD THAT GULF WOULD INCUR DAMAGE IN EXCESS OF THE CURRENT $27.6 MILLION RESERVE BALANCE?

A Gulf analyzed the Aggregate Damage Excedance Probabilities for various damage levels up to and in excess of $250 million. (See Table 4-1 of Exhibit No. __ (CJE-1), Schedule 5). According to Gulf's study, there is an 8.03% probability that there will be damage in any one year that exceeds the current reserve level of $27.6 million. In other words, a storm inflicting damage in an amount of approximately $30 million is likely to occur only once every 12 years.

Q WHAT RESULTS DOES THE STUDY SHOW FOR CATEGORY 1 AND 2 HURRICANES?

A On average, the most destructive Category 1 storm would cause mean damage of slightly less than $30 million. (*Id.,* Exhibit No. __ (CJE-1), Schedule 5 at 14). The damage from the most costly Category 2 storm would cause mean damage of approximately $50 million. (*Id.,* Exhibit No. __ (CJE-1), Schedule 5 at 15).

Q IS IT NECESSARY TO SET THE STORM RESERVE ACCRUAL TO COVER THE COSTS OF ALL TROPICAL STORMS OR HURRICANES REGARDLESS OF THE LEVEL OF SUCH STORMS?

A No. The storm reserve and associated accrual are only part of the framework for recovering storm restoration costs. The Commission has demonstrated its ability and willingness to promptly consider and act upon a utility's request to recover storm costs. As such, the storm reserve need not cover all storms. To do so would impose an unnecessary added burden on customers.

Rather, what is needed is a reasonable accrual and a reasonable reserve designed to cover the expected damage from the more common (but not all) storm events. In this instance, Gulf is seeking to establish the reserve at a level designed to provide for coverage for all storm damage. Such a "worst case" approach is only necessary if the storm reserve and associated accrual are the only means by which a utility is able to obtain coverage for damages from storms.

Q **HOW ARE CUSTOMERS AFFECTED BY THE PROPOSED $3.3 MILLION PER YEAR INCREASE IN CONTRIBUTIONS TO THE STORM RESERVE?**

A Customers will see their electricity rates increase unnecessarily. As I previously stated, customers would prefer to keep any money they can in their pockets, rather than have Gulf hold it for them to address an event which has not even occurred. This is particularly the case given the Commission's record of prompt action on storm recovery requests.

Q **DO GULF'S CUSTOMERS BENEFIT FROM HIGHER CONTRIBUTIONS TO FUND THE RESERVE?**

A No. As explained above, the current $3.5 million contribution and the current storm reserve of $27.6 million are more than sufficient to cover all but the most severe storms. ~~In contrast, the increase will benefit Gulf by increasing its cash flow. The storm accrual funds are not maintained in a separate account, but can be used to fund on-going Gulf operations~~. Finally, the risk of non-recovery for storm damage restoration costs will remain with customers because if a catastrophic storm or storms strike Gulf's service territory, customers will be surcharged to allow Gulf to recover restoration in excess of the storm reserve balance.

Q IS AN INCREASE IN THE RESERVE NECESSARY TO MAINTAIN THE STATUS QUO?

A No. The current reserve balance is sufficient to cover all Category 1 hurricanes, as well as all but the most severe Category 2 hurricanes. In fact, at the EAD chargeable to the reserve each year, the reserve balance is sufficient to provide coverage for four years. Thus, it is not necessary to increase the current funding level, and in fact, it would be sufficient for some years even if the accruals were stopped.

Q WHAT WOULD BE THE IMPACT ON THE STORM RESERVE IF ACCRUALS WERE STOPPED ENTIRELY?

A Over time, the level of the reserve will decline. However, absent a direct strike in the most populated portion of Gulf's service territory, the current reserve balance may be sufficient to cover the EAD funded from the reserve for the next four years. If losses remain at the levels experienced over the 2006-2010 period, the current reserve is more than capable of supporting storm recovery for several years, without any further customer contributions.

Q SHOULD THE COMPANY REVISE ITS STORM RESERVE ANALYSIS IN THE NEXT RATE CASE?

A Yes. Since the present analysis addresses all manner and strength of storms up to and including the most severe and damaging storms and excludes any benefits of the storm hardening program, the Commission should require that any subsequent study consider alternative levels of storm damage. Any subsequent study should evaluate the reserve performance taking into account only Category

1 (and potentially Category 2) storms. This approach gives recognition to the framework for addressing storm restoration costs – which recognizes that the annual accrual and reserve balance are not intended to cover the most destructive storms. A future analysis should also expressly consider how storm hardening efforts have reduced the risk of damage from hurricane or tropical storm events and the need to accrue monies for storm reserves.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A The storm reserve accrual should not be changed. The current reserve balance is sufficient to provide for coverage of the EAD funding from the reserve and also provides coverage for all Category 1 storms. A revised study should be submitted when Gulf next files a rate case or seeks to re-institute the storm reserve accrual and collection that shows what an appropriate reserve target is assuming coverage of *most* (Category 1 and 2) storms instead of *all* levels of storms.

Q **DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock. My business mailing address is 12655 Olive Blvd., Suite 335, St. Louis, Missouri 63141.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and President of J. Pollock, Incorporated.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Indiana, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court. A partial list of my appearances is provided in **Appendix B**.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J.Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J.Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. Currently, J.Pollock has offices in St. Louis, Missouri and Austin, Texas. J.Pollock is a registered Class I aggregator in the State of Texas.

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010

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90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Energy Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009

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81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008

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70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study, revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007

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61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007
41219	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	08/23/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06

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41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004
8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004

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8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002
7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001
7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001

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7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000

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Testimony Filed in Regulatory Proceedings
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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999
7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/1/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

APPENDIX C

<u>Procedures for Conducting a Class Cost-of-Service Study</u>

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a class cost-of-service study is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted class cost-of-service study recognizes two key cost causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per unit basis because they:

1. Operate at higher load factors;
2. Take service at higher delivery voltages; and
3. Use more electricity per customer.

A customer that purchases non-firm or interruptible service is receiving a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics.

Finally, a customer that assumes price risk, such as the case under Gulf's Schedule RTP (Real Time Pricing), is also less costly to serve. An RTP customer pays the hourly incremental cost plus a contribution to fixed costs. The incremental cost is not known until 24 hours prior to the next day. Thus, RTP is unlike any other rate.

All of these factors explain why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

CHAIRMAN GRAHAM: I'm sorry. Major Thompson.

MS. KLANCKE: Just one point of clarification. I believe the errata sheet was part of the exhibits to his deposition. Is that correct?

MS. KAUFMAN: I think so, yes.

MS. KLANCKE: Yes. And so that was already previously moved into the record, and I'll just make a notation with respect to -- it would be inclusive of the errata sheet, which is contained on the hearing CD.

CHAIRMAN GRAHAM: Okay. So noted.

MS. KLANCKE: Yes.

MS. KAUFMAN: Thank you.

MAJOR THOMPSON: Mr. Gorman hasn't been sworn in yet.

CHAIRMAN GRAHAM: Okay. Are there any other witnesses in the audience that have not been sworn? We can do this all at one time.

(Witness sworn.)

Thereupon,

MICHAEL P. GORMAN

was called as a witness on behalf of Federal Executive Agencies and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MAJOR THOMPSON:

Q. Could you please state your name for the record.

A. My name is Michael Gorman.

Q. Your business address and occupation?

A. My business address is 166 ninely -- excuse me, 16690 Swingley Ridge Road, Chesterfield, Missouri.

Q. And your occupation?

A. I'm a consultant with the firm of Brubaker & Associates.

Q. Did you file direct testimony in this hearing?

A. I did.

Q. Do you have any changes or corrections to that?

A. I have one correction. On page 41, line 14, that designation "BBB" in quotes should be struck, and the words "investment grade" should be inserted.

CHAIRMAN GRAHAM: I'm sorry, sir. Can you repeat that one more time.

THE WITNESS: Page 41, line 14, in quotes, "BBB" should be struck, and the words "investment grade" should be inserted.

CHAIRMAN GRAHAM: Okay.

BY MAJOR THOMPSON:

Q. Okay. If you were asked the same questions today, would your answers be the same?

A. They would.

MAJOR THOMPSON: Mr. Chairman, I would like to enter Mr. Gorman's testimony into the record.

CHAIRMAN GRAHAM: We will move his prefiled direct testimony into the record.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Increase in Rates by Gulf Power Company) **Docket No. 110138-EI**

Direct Testimony of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q **WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

A I will recommend a fair return on common equity and overall rate of return for Gulf Power Company ("Gulf Power" or "Company"). I will also comment on the Company's proposed critical peak rate option ("CPRO") for medium and large business customers who are served on time-of-use rates.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR GULF POWER'S RETURN ON EQUITY IN THIS PROCEEDING.**

A My recommendations and findings in this proceeding are summarized as follows.

1. As shown on my Exhibit MPG-1, I recommend an overall rate of return of 6.22%. This overall rate of return is based on a 9.75% return on equity, and my revised capital structure described below.
2. I recommend an adjustment to the regulatory capital structure based on an adjustment to the deferred tax balance.

Q **PLEASE DESCRIBE YOUR PROPOSED CHANGES TO THE COMPANY'S CPRO FOR MEDIUM AND LARGE BUSINESS CUSTOMERS.**

A I generally endorse the Company's proposal to implement a CPRO for medium and large business customers. However, I propose more transparent terms and conditions of this rate option. Specifically, I recommend the CPRO language be modified to include the following:

- A transparent description of when a critical peak can be declared including:
    1. an assessment of the forecasted temperatures for winter and summer periods;

2. Stated objectives for real-time pricing thresholds which can be relied on to declare a critical peak; and
3. General input as to when the Company could claim a critical peak due to personnel projections of system peak loads.

These proposals will be discussed in more detail later in this testimony.

RATE OF RETURN

Electric Utility Industry Market Outlook

Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A I have reviewed the credit rating and investment return performance of the electric utility industry. Based on the assessments described below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity. Further, electric utilities' stocks have exhibited strong return performance and are characterized as a safe investment.

Q PLEASE DESCRIBE THE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.

A Electric utilities' credit rating outlook has improved over the recent past and is now stable. Standard & Poor's ("S&P") recently provided an assessment of the credit rating of U.S. electric utilities for 2010. S&P's commentary included the following:

> **Solid Industry Fundamentals Support Stable Outlook**
>
> Throughout 2010, U.S. electric utilities performed well amid continuing <u>favorable access to capital</u>. With rebounding markets, external financing activity for the U.S. regulated electric utility industry was about $35 billion, well below the $48 billion in more

> difficult market conditions in 2009. Companies have continued to proactively pre-finance maturities, taking advantage of investor appetite and favorable spreads, and focused on strengthening their balance sheets and liquidity. Investor appetite for first mortgage bonds remained healthy, with deals continuing to be oversubscribed. <u>Credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to capital markets and credit</u>. Liquidity, an industry-wide strength, has been improving. Banking syndicates are expressing willingness to negotiate credit facilities, now with lengthening terms.[1]

Similarly, Fitch states:

> **Rating Outlook**
>
> <u>Stable Credit Outlook for Most Segments</u>: Relatively low prices for natural gas and power, low interest rates, open capital-market conditions, and a slow economic recovery forecasted by Fitch Ratings for 2011 are the foundation for a <u>stable credit outlook</u> for most business segments within the utilities, power, and gas (UPG) sector. Fitch's 2011 credit outlook for investor-owned gas and electric utilities, utility parent companies, pipelines, and midstream gas companies is stable. A significant exception is the negative 2011 credit outlook for competitive generators, whose profit margins and cash flows are subject to continuing compression

---

[1]Standard & Poor's RatingsDirect on the Global Credit Portal: "Industry Economic And Ratings Outlook: Stable Industry Outlook For U.S. Regulated Electric Utilities Supports Ratings," January 14, 2011, emphasis added.

> from low gas and power prices and an overhang of excess power capacity.[2]

Value Line also continues to characterize utility stock investments as a safe haven:

> **Conclusion**
>
> The main appeal of electric utility stocks continues to be the prospect of consistent income in the form of quarterly dividends, coupled with relative stability. Each utility in this Issue offers a dividend, which for the most part, is quite generous in relation to those in other industries. Although valuation concerns have arisen as of late due to the recent increase in utility stock prices, we believe that these equities remain a popular safe haven for conservative investors.[3]

EEI also opined as follows:

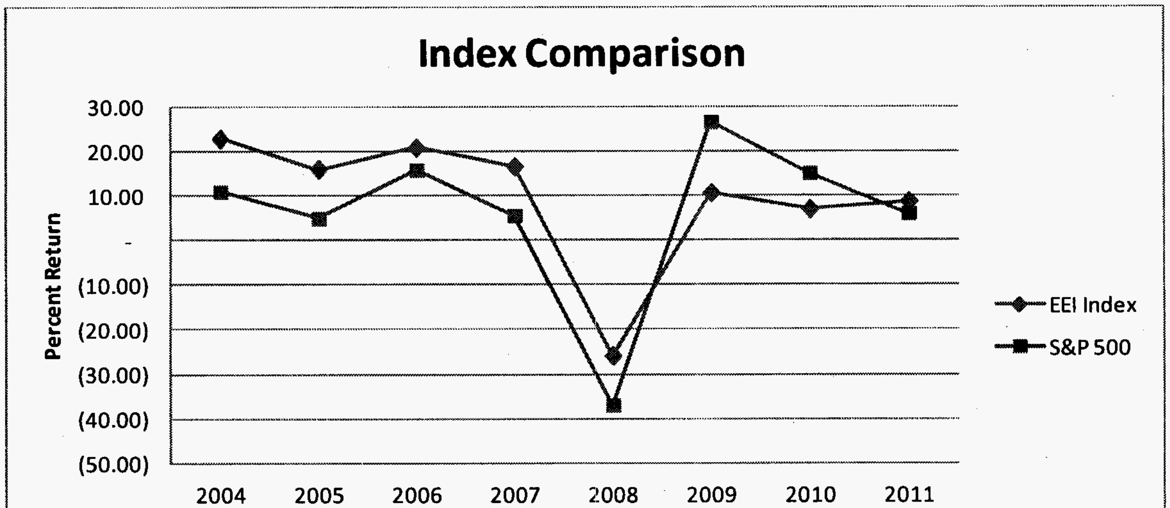
> There was little change during the first half of 2011 in the industry's long-term outlook. Many regulated utilities are engaged in capital spending programs that should, according to Wall Street analysts, help drive slow but steady earnings growth over the next several years.[4]

[2]Fitch Ratings: "2011 Outlook: U.S. Utilities, Power, and Gas," December 20, 2010, emphasis added.
[3]*Value Line Investment Survey*, November 26, 2010 at 139, emphasis added.
[4]*EEI Q2 2011 Financial Update* at 1.

Q PLEASE DESCRIBE ELECTRIC UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SIX YEARS.

A As shown in Figure 1 below, the Edison Electric Institute ("EEI") has recorded electric utility stock price performance compared to the market. The EEI data shows that its Electric Utility Index has outperformed the market over the last six years (2004-Second Quarter 2011).

Figure 1



Source: EEI Q2 2011 Stock Performance Financial Update, at Page 1.

During 2009 and 2010, the EEI Index underperformed the market, which is not unusual for stocks that are considered "safe havens" during periods of market turbulence.

In the first half of 2011, the EEI Index outperformed the market. EEI states the following:

> The EEI Index slightly outperformed the broad market averages during the first half of 2011, returning 8.8% compared with the Dow Jones' 8.6% return, the S&P 500's 6.0% return and the Nasdaq Composite's 4.6% return. However, the first half of the year was a distinct tale of two quarters, one that highlights the sector's return to its traditional role as a defensive investment following its reemphasis in recent years of core regulated businesses with slow but predictable earnings growth and steady dividends.[5]

Gulf Power's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF GULF POWER.

A The market's assessment of Gulf Power's investment risk is best described by credit rating analysts' reports. Gulf Power currently has an "A" corporate bond rating from S&P and Fitch, and an "A3" bond rating from Moody's.

Standard & Poor's states:

> Standard & Poor's Ratings Services' ratings on Gulf Power Co. reflect the consolidated credit profile of its parent, Southern Co.

[5] *EEI Q2 2011 Financial Update* at 1, emphasis added.

Southern has an excellent consolidated business risk profile characterized by stable regulated electric utility operations in Georgia, Alabama, Mississippi, and Florida, which contribute more than 90% of consolidated operating income. The business risk profile benefits from operations in jurisdictions with generally constructive regulatory frameworks, combined with effective management of regulatory relations; strong operating performance and high availability and capacity utilization factors for owned generation; regulatory and operating diversity with a presence in four states; competitive rates for the region that provide some cushion for future rate increases to recover fuel costs and increasing capital expenditures; lack of meaningful unregulated operations; and prudent and reasonably conservative management and financial policies.

Outlook

We base the stable outlook on Southern Company and its affiliates on the company's consistent, regulated electric utility operations, which benefit from constructive regulatory frameworks, strong operations, a large service territory with attractive demographics, and proactive and generally conservative management and financial risk practices.[6]

[6] Standard & Poor's RatingsDirect on the Global Credit Portal: "Gulf Power Co.," September 28, 2011.

Further, Fitch states:

Rating Rationale

- Fitch affirmed the ratings of Gulf Power Company on Sept. 3, 2010. The Rating Outlook is Stable.
- The ratings and Stable Outlook for Gulf reflect Fitch's expectation that the credit metrics should improve from 2009 cyclical lows. The Stable Outlook also reflects a manageable capital-expenditure program, modest debt maturities, and historically constructive rate outcomes.
- Gulf's cash flow stability is enhanced by several annually adjusted rate riders that provide timely recovery of all prudent costs related to fuel, purchased costs, and environmental expenditures outside of base rates.
- Fitch expects the still-weak Florida economy and the uncertain utility regulatory situation in the state to gradually improve. While Gulf is heavily dependent on coal-fired generation capacity that must comply with changing emissions standards, the fuel and environmental recovery clauses promote timely recovery of associated costs.[7]

[7]Fitch Ratings Global Power U.S. and Canada Full Rating Report: "Gulf Power Company," October 5, 2010, provided by Gulf Power as Exhibit RST-1, Schedule 8, page 1 of 5.

Q WHAT ARE THE IMPORTANT TAKEAWAYS FROM THE CREDIT ANALYSTS' REVIEW OF GULF POWER'S INVESTMENT RISK?

A The important takeaways are as follows:

1. Credit rating reports indicate that Gulf Power has a stable credit standing, with constructive regulatory frameworks, stable cash flows, and has a manageable capital expenditure program. Together, these indicate that Gulf Power is a reasonably stable investment, based on its low-risk regulated operations.

Gulf Power's Capital Structure

Q WHAT IS GULF POWER'S 2012 PROPOSED CAPITAL STRUCTURE?

A The Company's 2012 proposed capital structure is shown in Table 1 below.

TABLE 1

Gulf Power's
Proposed Capital Structure

Description	Regulatory Capital Weight (1)	Investor Capital Weight (2)
Long-Term Debt	39.29%	47.21%
Short-Term Debt	1.07%	1.29%
Preference Stock	4.36%	5.24%
Common Equity	38.50%	46.26%
Customer Deposits	1.27%	–
Deferred Taxes	15.34%	–
Investment Tax Credit	0.17%	–
Total	100.00%	100.00%

Source: Exhibit No. ___ (RJM-1), Schedule 12.

Q **ARE YOU PROPOSING ANY ADJUSTMENTS TO GULF POWER'S PROPOSED CAPITAL STRUCTURE?**

A Yes. As described in the testimony of my colleague, Mr. Greg Meyer, we could not verify the total Company amount of accumulated deferred income taxes. Based on the Company's books and records in this proceeding, we believe that the total Company deferred income taxes should be $536.6 million rather than the $492.1 million included in the Company's filing. (McMillan Ex. No. ___ (RJM-1) Schedule 12, page 2).

Hence, as described in Mr. Meyer's testimony, we are proposing to use the amount of accumulated deferred taxes that we believe can be verified in the Company's filing to produce an appropriate regulatory capital structure. If the Company can explain the difference between the amount of accumulated deferred taxes which are readily determinable from its books and records in this proceeding, and that are actually used in its proposed regulatory capital structure, we may be willing to remove this proposed capital structure adjustment.

However, until that happens I recommend the Commission adopt the capital structure for regulatory purposes shown below in Table 2.

TABLE 2

Gorman's
Proposed Capital Structure

Description	Regulatory Capital Weight (1)	Investor Capital Weight (2)
Long-Term Debt	38.71%	47.21%
Short-Term Debt	1.06%	1.29%
Preference Stock	4.30%	5.24%
Common Equity	37.93%	46.26%
Customer Deposits	1.25%	–
Deferred Taxes	16.59%	–
Investment Tax Credit	0.17%	–
Total	100.00%	100.00%

Source: Exhibit MPG-1.

Q **WHAT IS THE OVERALL RATE OF RETURN BASED ON YOUR PROPOSED RETURN ON EQUITY?**

A As shown on Exhibit MPG-1, Gulf Power's overall rate of return, based on a return on equity of 9.75% and my revised capital structure, is 6.22%.

RETURN ON EQUITY

Gulf Power's Market Cost of Common Equity

Q **PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."**

A A utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Public Serv. Commission of West Virginia,* 262 U.S. 679 (1923) *and Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR GULF POWER.

A I have used several models based on financial theory to estimate Gulf Power's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using analyst growth data; (2) a sustainable growth DCF model; (3) a multi-stage growth DCF model; (4) a risk premium ("RP") model, and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities that I have determined reflect investment risk similar to Gulf Power.

Q **HOW DID YOU SELECT A UTILITY PROXY GROUP SIMILAR IN INVESTMENT RISK TO GULF POWER TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?**

A I relied on the same electric utility proxy group used by Gulf Power witness Dr. Vander Weide to estimate Gulf Power's return on equity. However, I excluded three companies that have been engaged in merger and acquisitions ("M&A") activity. Excluding companies engaged in M&A activity was a proxy group selection criterion of Dr. Vander Weide (Vander Weide Direct at 29); however, certain proxy companies became engaged in this activity after he compiled his proxy group.

I excluded Duke Energy, Progress Energy and Nextera Energy from his proxy group. I excluded companies involved in M&A activity because observable stock price information may reflect the M&A outlooks rather than the stand-alone utility company's outlooks. This, in turn, could significantly skew the equity return estimate.

Q **HOW DOES THE PROXY GROUP INVESTMENT RISK COMPARE TO GULF POWER'S INVESTMENT RISK?**

A The proxy group is shown on Exhibit MPG-2. This proxy group has an average corporate credit rating from S&P of "BBB+," which is lower than S&P's credit rating for Gulf Power of "A." The proxy group's credit rating from Moody's is "Baa2," which is lower than Gulf Power's credit rating from Moody's of "A3." The proxy group has comparable total investment risk to Gulf Power.

The proxy group has an average common equity ratio of 45.9% (including short-term debt) from AUS Utility Reports ("AUS") and 47.7% (excluding short-term debt) from *Value Line* in 2010. This proxy group's common equity ratio is higher than Gulf Power's test year common equity ratio of 46.26% including short-term debt. Gulf Power's common equity ratio is lower than that of the proxy group average but within the variance within the proxy group.

I also compared Gulf Power's business risk to the business risk of my proxy group based on S&P's ranking methodology. Gulf Power has an S&P business risk profile of "Excellent," which is identical to the S&P business risk profile of the proxy group. The S&P business risk profile score indicates that Gulf Power's business risk is comparable to that of the proxy group.

S&P ranks the business risk of a utility company as part of its corporate credit rating review. (S&P considers total investment risk in assigning bond ratings to issuers, including utility companies. In analyzing total investment risk, S&P considers both the business risk and the financial risk of a corporate entity, including a utility company.) S&P's business risk profile score is based on a five-notch credit rating starting with "Vulnerable" (highest risk) to "Excellent" (lowest risk). The business risk of most utility companies falls within the lowest risk category, "Excellent," or the category one notch higher, "Strong."[8]

Based on these proxy group selection criteria, I believe that the proxy group reasonably approximates the investment risk of Gulf Power, and that it can be used to estimate a fair return on equity for Gulf Power.

[8] Standard & Poor's: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.

Discounted Cash Flow Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\,.\,.\,. \; \frac{D_\infty}{(1+K)^\infty} \quad \text{where} \qquad \text{(Equation 1)}$$

P_0 = Current stock price

D = Dividends in periods 1 - ∞

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return

D_1 = Dividend in first year

P_0 = Current stock price

G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q **PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.**

A As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q **WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?**

A I relied on the average of the weekly high and low stock prices over a 13-week period ended September 16, 2011. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflect current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q **WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?**

A I used the most recently paid quarterly dividend, as reported in *The Value Line Investment Survey*. This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market required return on common equity, one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[9] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL Financial and Reuters. All such projections were available on September 22, 2011, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is more representative

[9]See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

of general market expectations. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q WHAT IS THE GROWTH RATE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A The growth rates I used in my DCF analysis are shown in Exhibit MPG-3. The average and median growth rates for my proxy group are 5.26% and 5.33%, respectively.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit MPG-4, the average and median constant growth DCF returns for the proxy group are 10.05% and 10.11%.

Q DO YOU HAVE ANY COMMENTS CONCERNING THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The three- to five-year growth rate exceeds a long-term sustainable growth rate as required by the constant growth DCF model.

Q WHY DO YOU BELIEVE THE PROXY GROUP'S THREE- TO FIVE-YEAR GROWTH RATE IS IN EXCESS OF A LONG-TERM SUSTAINABLE GROWTH?

A The three- to five-year growth rate of the proxy group exceeds the growth rate of the overall U.S. economy. As developed below, the consensus of published economists projects that the U.S. Gross Domestic Product ("GDP") will grow at a rate of no more than 5.1% and 4.7% over the next 5 and 10 years, respectively.

A company cannot grow, indefinitely, at a faster rate than the market in which it sells its products. The U.S. economy, or GDP, growth projection represents a ceiling, or high-end, sustainable growth rate for a utility over an indefinite period of time.

Q **WHY IS THE GDP GROWTH PROJECTION CONSIDERED A CEILING GROWTH RATE FOR A UTILITY?**

A Utilities cannot sustain indefinitely a growth rate that exceeds the growth rate of the overall economy. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas. The Energy Information Administration ("EIA") has observed that utility sales growth is less than U.S. GDP growth, as shown in Exhibit MPG-5. Utility sales growth has lagged behind GDP growth for more than a decade. Hence, nominal GDP growth is a very conservative, albeit overstated, proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, GDP growth is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q **IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?**

A Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial

Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[10]

Sustainable Growth DCF

Q PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A A sustainable growth rate is based on the percentage of the utility's earnings that are retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings are put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings. As shown in Exhibit MPG-6, *Value Line* projects that the proxy group

[10]"Fundamentals of Financial Management," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.

will have a declining dividend payout ratio over the next three to five years. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term retention ratio will help us gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market to book ratio and on *Value Line's* three-to-five year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit MPG-7, page 1 of 2, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 4.66% and 4.90%, respectively.

Q WHAT IS THE CONSTANT GROWTH DCF ESTIMATE USING THIS SUSTAINABLE LONG-TERM GROWTH RATE?

A A DCF estimate based on this sustainable growth rate is developed in Exhibit MPG-8. As shown there, a sustainable growth DCF analysis produces group average and median DCF results of 9.43% and 9.17%, respectively.

The sustainable growth DCF result is based on the dividend and price data used in my constant growth DCF study (using analyst growth rates) and the sustainable growth rate discussed above and developed in Exhibit MPG-7.

Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the GDP growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 4.9%.

Q HOW DID YOU DETERMINE THE CONSENSUS REASONABLE SUSTAINABLE LONG-TERM GROWTH RATE?

A A reasonable growth rate that can be sustained in the long run should be based on consensus analysts' projections. *Blue Chip Economic Indicators* publishes consensus GDP growth projections twice a year. Based on its latest issue, the consensus economists' published GDP growth rate outlook is 5.1% to 4.7% over the next 5 and 10 years, respectively.[11]

Therefore, I propose to use the midpoint (4.9%) of the consensus economists' projected average 5-year and 10-year GDP consensus growth rates, as published by *Blue Chip Economic Indicators,* as an estimate of sustainable long-term growth. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published economist projections. *Blue Chip Economic Indicators'* projections reflect real GDP growth of 3.0% and 2.6%, and GDP inflation of 2.1% and 2.1%[12] over the 5-year and 10-year projection periods, respectively.

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes. The U.S. EIA in its Annual Energy Outlook projects the real GDP out until 2035. In its 2011 Annual Report, the EIA projects real GDP through 2035 to be in the range of 2.1% to 3.2%, with a midpoint or reference case of 2.7%.[13]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections -- including one for the period 2016-2019. The CBO, like

[11] *Blue Chip Economic Indicators*, March 10, 2011 at 15.
[12] GDP growth is the product of real and inflation GDP growth.
[13] DOE/EIA Annual Energy Outlook 2011 With Projections to 2035, April 2011.

the consensus *Blue Chip Economic* projections, is projecting real GDP growth of 2.3% during the period beyond five years, with GDP price inflation around 1.6%. The CBO's projections are lower than the consensus economists as published by *Blue Chip Economic Indicators*.

The real GDP and nominal GDP growth projections made by the U.S. EIA and those made by the CBO support the use of the consensus analyst 5-year and 10-year projected GDP growth outlooks as a reasonable market assessment of long-term prospective GDP growth.

Q WHAT STOCK PRICE, DIVIDEND AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A I relied on the same 13-week stock price and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The transition period begins in year 6 and ends in year 10. For the long-term sustainable growth rate starting in year 11, I used 4.9%, the average of the consensus economists' 5-year and 10-year projected nominal GDP growth rates.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A As shown in Exhibit MPG-9, the average and median DCF returns on equity for the proxy group are 9.78%.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The results from my DCF analyses are summarized in Table 3 below:

TABLE 3

Summary of DCF Results

Description	Return
Constant Growth DCF Model (Analysts' Growth)	10.05%
Constant Growth DCF Model (Sustainable Growth)	9.43%
Multi-Stage Growth DCF Model	9.78%
Average DCF Return	9.75%

For reasons set forth above, I believe my constant growth DCF model based on analysts' growth is overstated because short-term analyst growth rate projections exceed reasonable estimates of long-term sustainable growth. Therefore, the DCF model based on analysts' growth rate estimates should not be used on a stand-alone basis. I recommend it be averaged with my other DCF estimates to produce a reasonable DCF point estimate that can be used to derive Gulf Power's return on equity. The constant growth DCF model based on the sustainable growth approach produces a growth rate that is sustainable in the long term in comparison to GDP growth, but that growth rate may not reflect analysts' short-term growth outlooks. The multi-stage growth DCF model return reflects the expectation of changing growth rates over time. Based on all my DCF studies, I find that a reasonable DCF return estimate is 9.75%.

Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through the second quarter of 2011. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields. I selected the period 1986 through the second quarter of 2011 because public utility stocks consistently traded at a premium to book value during that period This is illustrated in Exhibit MPG-10, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit MPG-11, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.21%. Of the 26 observations, 20 indicated risk premiums fall in the range of 4.40% to 6.09%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit MPG-12, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.79% over the period 1986 through the second quarter of 2011. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 4.62% over this time period.

Q DO YOU BELIEVE THAT THESE EQUITY RISK PREMIUM ESTIMATES ARE BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE RESULTS CONCERNING CONTEMPORARY MARKET CONDITIONS?

A No. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data. Conversely, studies have recommended that use of "actual achieved return data" should be based on very long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. However, these short-term abnormal actual returns would be smoothed over time and the achieved actual returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods.

Q **BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE GULF POWER'S COST OF EQUITY IN THIS PROCEEDING?**

A The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit MPG-13. On that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 30 years. As shown in this exhibit, the 2008 utility bond yield spreads over Treasury bonds for "A" rated and "Baa" rated utility bonds are 2.25% and 2.97%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for 2009 are 1.96% and 2.98%, respectively. In 2010, these spreads declined to 1.21% and 1.71%, respectively. These utility bond yield spreads over Treasury bond yields are now lower than the 30-year average spreads of 1.59% and 1.99%, respectively.

A current 13-week average "A" rated utility bond yield of 4.92%, when compared to the current Treasury bond yield of 3.88% as shown in Exhibit MPG-14, page 1 of 3, implies a yield spread of around 1.04%. This current utility bond yield is lower than the 30-year average spread for "A" utility bonds of 1.59%. The current spread for the "Baa" utility yields of 1.48% is also lower than the 30-year average spread of 1.99%.

These reduced utility bond yield spreads are clear evidence that the market considers the utility industry to be a relatively low risk investment and demonstrates that utilities continue to have strong access to capital.

Q HOW DID YOU ESTIMATE GULF POWER'S COST OF COMMON EQUITY WITH THIS RISK PREMIUM MODEL?

A I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending September 16, 2011 was 3.88%, as shown in Exhibit MPG-14, page 1 of 3. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 4.2%, and a 10-year Treasury bond yield to be 3.1%.[14] Using the

[14] *Blue Chip Financial Forecasts*, September 1, 2011 at 2.

projected 30-year bond yield of 4.2%, and a Treasury bond risk premium of 4.40% to 6.09%, as developed above, produces an estimated common equity return in the range of 8.60% (4.20% + 4.40%) to 10.29% (4.20% + 6.09%), with a midpoint of 9.45%. Because of the very large difference between current and projected Treasury bond rates, I recommend an equity risk premium above the midpoint of my estimated range. Therefore, rather than relying on the 9.45% midpoint of this range, I recommend moving it halfway between the midpoint (9.45%) and the high-end range of 10.3%. Therefore, my proposed equity risk premium return is 9.87%, rounded to 9.90%. I believe this is a reasonable return estimate recognizing the unusually low level of long-term Treasury bond yields in the current market.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "Baa" rated utility bonds for the period ending September 16, 2011 of 5.36%. Adding the utility equity risk premium of 3.03% to 4.62%, as developed above, to a "Baa" rated bond yield of 5.36%, produces a cost of equity in the range of 8.39% (5.36% + 3.03%) to 9.98% (5.36% + 4.62%), with a midpoint of 9.19%. Again, recognizing the low bond yields currently, I recommend moving to halfway between the midpoint (9.19%) and high-end (9.98%), or 9.59%, rounded to 9.60%.

My risk premium analyses produce a return estimate in the range of 9.60% to 9.90%, with a midpoint estimate of approximately 9.75%.

Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i

R_f = Risk-free rate

R_m = Expected return for the market portfolio

B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are nondiversifiable risks. Nondiversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as non-systematic risks. In a broad sense, systematic risks are market risks, and non-systematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.2%.[15] The current 30-year Treasury bond yield is 4.34%. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.2% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common-stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

[15] *Blue Chip Financial Forecasts*, September 1, 2011 at 2.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q **WHAT BETA DID YOU USE IN YOUR ANALYSIS?**

A As shown in Exhibit MPG-15, the proxy group average *Value Line* beta estimate is 0.71.

Q **HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?**

A I derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar's *Stocks, Bonds, Bills and Inflation 2011 Classic Yearbook* publication estimates the historical arithmetic average real market return over the period 1926 to 2010 as 8.7%.[16] A current consensus analysts' inflation

[16]Morningstar, Inc. Ibbotson *SBBI 2011 Classic Yearbook* at 86.

projection, as measured by the Consumer Price Index, is 2.2%.[17] Using these estimates, the expected market return is 11.09%.[18] The market risk premium then is the difference between the 11.09% expected market return, and my 4.2% risk-free rate estimate, or 6.89%, rounded to 6.90%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2011 Classic Yearbook*. Over the period 1926 through 2010, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 11.9%,[19] and the total return on long-term Treasury bonds was 5.9%.[20] The indicated market risk premium is 6.0% (11.9% - 5.9% = 6.0%).

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?

A Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 6.0% to 6.7%. My market risk premium falls in the range of 6.0% to 6.9%. My average market risk premium of 6.45% (rounded to 6.5%) is within Morningstar's range.

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2010. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments.

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[17] *Blue Chip Financial Forecasts*, September 1, 2011 at 2.
[18] $\{ [(1 + 0.087) * (1 + 0.024)] - 1 \} * 100$.
[19] Morningstar, Inc. Ibbotson *SBBI 2011 Classic Yearbook* at 86.
[20] Id.

The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with the Treasury bond and is the best approximation of a truly risk-free rate. I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 6.7% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.5% and not 6.7%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 6.0%.[21]

Finally, Morningstar found that the 6.7% market risk premium based on the S&P 500 was impacted by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable. Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in

[21]Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. Morningstar, Inc. *Ibbotson SBBI 2011 Valuation Yearbook* at 54.

dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 6.0%.[22]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit MPG-16, based on a market risk premium of 6.5%, a risk-free rate of 4.2%, and a beta of 0.71, my CAPM analysis produces a return of 8.82%. Using Morningstar's high-end market risk premium of 6.7% would produce a CAPM return of 8.96%. I am concerned with the low estimates produced by my CAPM analysis at this time. I will use the high end of this range, 8.96% (rounded to 9.00%).

Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR GULF POWER?

A Based on my analyses, I estimate Gulf Power's current market cost of equity to be 9.75%.

TABLE 4

Return on Common Equity Summary

Description	Results
DCF	9.75%
Risk Premium	9.75%
CAPM	9.00%

[22] *Id.* at 66.

My recommended return on common equity of 9.75% is supported by my DCF and risk premium studies. Because Treasury bond yields are currently at abnormally low levels, I am placing minimal weight on the results of my CAPM study at this time.

Financial Integrity

Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR GULF POWER?

A Yes. I have reached this conclusion by comparing the key credit rating financial ratios for Gulf Power at its proposed capital structure, and my return on equity to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of the utility company and related bond rating. On May 27, 2009 S&P expanded its matrix criteria[23] by including additional business and financial risk categories. Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most electric utilities have a business risk profile of "Excellent" or "Strong." The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the

[23] S&P updated its credit metric guidelines on November 30, 2007, and incorporated utility metric benchmarks with the general corporate rating metrics.

electric utilities have a financial risk profile of "Aggressive." Gulf Power has an "Excellent" business risk profile and an "Intermediate" financial risk profile.

Q **PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.**

A S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of Gulf Power's total credit risk exposure. S&P publishes a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: (1) debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"), (2) Funds From Operations ("FFO") to total debt, and (3) total debt to total capital.

Q **HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?**

A I calculated each of S&P's financial ratios based on Gulf Power's cost of service for retail operations. While S&P would normally look at total consolidated financial ratios in its credit review process, my investigation in this proceeding is to judge the reasonableness of my proposed cost of capital for rate-setting in Gulf Power's regulated utility operations. Hence, I am attempting to determine whether the rate of return and cash flow generation opportunity reflected in my proposed rate of return for Gulf Power will support target investment grade bond ratings and Gulf Power's financial integrity.

Q DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT ("OBSD")?

A Yes. As shown in Exhibit MPG-17, page 3 of 4, I used an OBSD amount of $33.9 million. This OBSD is attributed to Gulf Power's operating leases and purchase power agreements as estimated by S&P.

Q HOW DID YOU ESTIMATE GULF POWER'S OBSD?

A The OBSD is estimated by S&P and can be found in Exhibit MPG-17, page 4 of 4. Because I am focused on Florida retail operations, I included only the amount of total Gulf Power OBSD that is clearly tied to provision of retail electric utility service in Florida. Therefore, I only included the amount of OBSD attributable to operating leases.

The OBSD obligations were stated on a total Company basis. However, for the operating characteristics in determining FFO and EBITDA, I allocated a portion of the debt interest expense and debt amortization imputations associated to OBSD to Florida retail operations. A portion of total Company imputed interest and amortization expense was allocated to Florida based on an allocation of Florida rate base to total Company rate base.

Q PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR GULF POWER.

A The S&P financial metric calculations for Gulf Power are developed on Exhibit MPG-17, page 1 of 4.

As shown on Exhibit MPG-17, page 1 of 4, column 1, based on an equity return of 9.75%, Gulf Power will be provided an opportunity to produce a debt to EBITDA ratio of 3.8x. This is at the high end of S&P's new "Significant" guideline range of 3.0x to 4.0x.[24] This ratio supports an investment grade credit rating.

Gulf Power's retail operations FFO to total debt coverage at a 9.75% equity return would be 26%, which is within the new "Significant" metric guideline range of 20% to 30%. The FFO/total debt ratio will support an investment grade bond rating.

Finally, Gulf Power's total debt ratio to total capital is 55%. This is within the new "Aggressive" guideline range of 50% to 60%. This total debt ratio will support an investment grade bond rating.

At my recommended return on equity and Gulf Power's proposed capital structure, the Company's financial credit metrics are supportive of its current investment grade "~~BBB~~" utility bond rating.

Q **DO YOU BELIEVE THIS CREDIT METRIC EVALUATION OF GULF POWER AT YOUR PROPOSED RETURN ON EQUITY PROVIDES MEANINGFUL INFORMATION TO HELP THE COMMISSION DETERMINE THE APPROPRIATENESS OF YOUR RECOMMENDATION?**

A Yes. While S&P calculates these credit metrics based on total Company operations, and not the retail operations of Gulf Power (as I have performed in this study), they still provide meaningful information to evaluate the reasonableness of my proposed rate of return for Gulf Power in this case. Further, while credit rating agencies also consider other financial metrics and

[24]Standard & Poor's RatingsDirect: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

qualitative considerations, these metrics are largely driven by the cost of service items of depreciation expense and return on equity. Hence, to the extent these important aspects of cost of service impact Gulf Power's internal cash flows, the relative impact on Gulf Power will be measured by these credit metrics. As illustrated above, an authorized return on equity of 9.75% will support internal cash flows that will be adequate to maintain Gulf Power's current investment grade bond rating.

RESPONSE TO GULF POWER WITNESS DR. JAMES VANDER WEIDE

Q WHAT IS GULF POWER'S RETURN ON EQUITY RECOMMENDATION?

A Gulf Power's rate of return witness, Dr. Vander Weide, recommends a return on equity of 11.7%, which is based on an estimated proxy group return on equity of 10.8%, increased by 0.90% to include a leverage risk return on equity adder. This leverage return adder is based on Dr. Vander Weide's belief that Gulf Power has greater financial risk than the proxy group. (Vander Weide Direct at 4).

Q HOW DID DR. VANDER WEIDE DEVELOP HIS RETURN ON EQUITY RANGE?

A Dr. Vander Weide developed his return on equity recommendation by applying the DCF, Risk Premium and CAPM models to a utility proxy group. Dr. Vander Weide arrived at his recommendations by reviewing Gulf Power's business operations, market conditions, and utility industry trends at the time of his filing.

Q PLEASE SUMMARIZE DR. VANDER WEIDE'S PROPOSED RETURN ON EQUITY FOR GULF POWER.

A As shown below in Table 5, his analyses produce an average return on equity of 10.8% and a range of 10.7% to 11.0%. Dr. Vander Weide increased his proxy group estimated return range by 0.26% to account for flotation costs. However, as I will discuss in more detail below, making reasonable adjustments to Dr. Vander Weide's DCF and CAPM studies produces a return on equity for Gulf Power of well less than 10%. Dr. Vander Weide's return on equity adders for a leverage adjustment and flotation cost should be rejected.

Q HOW DID DR. VANDER WEIDE DEVELOP HIS LEVERAGE ADJUSTMENT?

A He develops this on his Exhibit ___ (JVW-1), Schedule 10. On that schedule, he develops a post-tax cost of equity using his proposed 10.8% cost of equity, and the market weighted average capital structure for his proxy group. This produced a weighted average cost of capital, post-tax, of 7.337%.

He then estimated the return on common equity that would produce the same post-tax weighted average cost of capital (7.337%) when applied to Gulf Power's book value capital structure. As shown on his Schedule 10, a return on book value equity at 11.7% would produce the same post-tax cost of equity on Gulf Power's book value capital structure, as he produced using the market value capital structure of his proxy group.

TABLE 5

Gulf Power's ROE Analysis

Model	Vander Weide Proposed	Adjusted
DCF	10.7%	10.1%
Ex Ante Risk Premium	11.0%	9.8%
Ex Post Risk Premium	10.8%	9.5%
CAPM Historical (MRP)	9.2%	9.0%
CAPM DCF (MRP)	10.7%	
Range	9.2% - 11.0%	9.0% - 10.1%
Point Estimate	10.8%	9.6%
Leverage Adder	0.9%	Reject
Recommendation	11.70%	9.6%

Sources:
Vander Weide Direct at 41, 46 and 47.

Q WHY IS DR. VANDER WEIDE'S PROPOSED LEVERAGE EQUITY RETURN ADDER UNREASONABLE?

A The leverage adjustment increases the return on equity to reflect Gulf Power's greater book value financial risk compared to its market value financial risk. However, such an adjustment to the equity return is erroneous for at least two reasons.

First, Dr. Vander Weide's contention that an adjustment should be made for differentials in book value and market value financial risk is without merit. The implicit premise of Dr. Vander Weide's leverage adjustment is that financial risk is measured differently using book value capitalization versus market value capitalization. This premise is without merit, because the Company's financial risk is tied to both its book value capitalization which in turn drives its market value capitalization. They are not separate factors. Second, Dr. Vander Weide's proposed leverage adjustment is really nothing more than a flawed market-to-book ratio adjustment. The leverage equity return adder results in an excess return on incremental utility plant investments.

For these reasons, the leverage adjustment is without merit, and should continue to be rejected by the Commission just as it was in Gulf Power's last rate case.

Q WHY DO YOU BELIEVE THAT A COMPANY DOES NOT HAVE DIFFERENT FINANCIAL RISK WHETHER IT IS MEASURED ON BOOK VALUE OR MARKET VALUE CAPITAL STRUCTURE?

A The company's financial risk concerns its ability to meet its financial obligations. Its ability to meet its financial obligations is tied to its ability to reliably produce internal generation of earnings and cash to pay its financial obligations. A company does not have one level of financial risk based on its book value capital structure, and another level of financial risk based on its market value capital structure.

Q HOW DOES BOOK VALUE LEVERAGE ESTABLISH A COMPANY'S FINANCIAL RISK?

A Book value leverage represents the utility's contractual obligations to pay debt interest and principal payments. These book value financial obligations must be paid from utility operating cash flows.

In generating free cash flow, the utility must make debt interest payments from operating income, and produce net cash flow after interest payments are made to support debt principal payments, construction expenditures, and to pay common dividends. Internal cash flows must support book value leverage. If cash flows are not adequate to meet book value obligations, the company can be forced into default. Financial risk concerns the likelihood a utility cannot pay these financial obligations.

The market value capital structure leverage does not measure whether a utility's earnings and free cash flow will cover its contractual financial obligations. These cash flows do drive stock valuations which produce the market capitalization structure. Nevertheless, the resulting stock valuations and market capitalization do not describe how reliably the internally generated cash flows will cover the fixed financial obligations of the company.

For these reasons, the financial risk is best described by the book value financial obligations in relationship to the cash flows produced on the company's books and records.

Q **WHY WILL DR. VANDER WEIDE'S LEVERAGE RETURN ADDER PROVIDE EXCESSIVE COMPENSATION ON INCREMENTAL UTILITY PLANT INVESTMENTS?**

A Because it will provide Gulf Power an excessive risk adjusted return on incremental plant investments, I will use Dr. Vander Weide's DCF results to illustrate this point.

If Gulf Power were to repurchase its own stock, it would expect to earn a market-based return of 10.80% based on Dr. Vander Weide's unadjusted DCF results. However, if the Commission accepted Dr. Vander Weide's leverage adjusted return, it could earn a return on incremental utility plant investments of 11.70% (the 10.80% plus 0.90% leverage adjustment).

If the utility was considering its options for reinvesting its retained earnings, it could be faced with the alternative investments of: (1) repurchase its own stock at a 10.80% return, or (2) invest in new utility plant at a 11.70% return. These are comparable risk investments because utility plant investments drive earnings, and earnings drive dividends and stock price. Under Dr. Vander Weide's proposal, the utility would be encouraged to gold-plate utility plant investment because it would be provided with an above-market risk adjusted return on such investments. Providing a utility an incentive to earn more than a fair risk adjusted return on utility plant investments will result in rates not being just and reasonable.

Q **WHY IS DR. VANDER WEIDE'S FLOTATION COST ADJUSTMENT FLAWED?**

A Dr. Vander Weide increased his DCF, risk premium and CAPM estimates by approximately 0.26% to include a flotation cost adjustment. This flotation cost adjustment is not based on Gulf Power actual common stock flotation cost and should therefore be rejected. Rather, as discussed at page 27 and Appendix 3 of Dr. Vander Weide's direct testimony, he derives a flotation cost adjustment based on published academic literature. Because he does not show that his adjustment is based on Gulf Power's actual and verifiable flotation expenses, there simply are no means of verifying whether Dr. Vander Weide's proposal is reasonable or appropriate.

Q **PLEASE DESCRIBE DR. VANDER WEIDE'S DCF ANALYSIS.**

A Dr. Vander Weide applied the traditional DCF model to a utility proxy group. Based on his utility group, his DCF study produces a return in the range of 10.7% to 11.4%. (Vander Weide Direct at 30 and Schedule 1).

Q **DO YOU TAKE ISSUE WITH DR. VANDER WEIDE'S DCF ANALYSES?**

A Yes. I have two major issues concerning his DCF analyses. Dr. Vander Weide's constant growth DCF study is overstated because the analysts' three- to five-year growth rates he uses are not reasonable estimates of long-term sustainable growth. The constant growth DCF model used by Dr. Vander Weide requires an estimated long-term sustainable growth. In contrast, the analysts' growth rates he relies on reflect only the outlooks over the next three to five years. To the extent the analysts' growth rate estimates are not reasonable estimates of long-term sustainable growth, then the DCF return estimate he produces from this study is not reliable. Because the analysts' growth rates exceed a reasonable estimate of long-term sustainable growth, Dr. Vander Weide's DCF return estimate is inflated and should be rejected.

Second, I believe his DCF return estimate is unreasonable because he relies on a quarterly compounding version of the DCF model. For the reasons set forth below, the quarterly compounding of the DCF model overestimates a utility's cost of capital because it provides utilities with an opportunity to earn the dividend reinvestment return twice: first, through authorized returns on equity and earnings to the utility, and a second time after dividends are actually paid to investors and reinvested in alternative investments to the utility stock the dividend was earned upon.

Q **PLEASE DESCRIBE WHY YOU BELIEVE DR. VANDER WEIDE'S THREE- TO FIVE-YEAR ANALYSTS' GROWTH RATE PROJECTIONS ARE NOT REASONABLE ESTIMATES OF LONG-TERM SUSTAINABLE GROWTH.**

A As shown on his Schedule 1, page 1, the growth rates from his proxy group in every instance but a few exceed the projected nominal growth of the U.S. GDP. As stated above, consensus economists' projections of long-term growth for the U.S. GDP are around 4.9%. In contrast, of Dr. Vander Weide's 24 utility company proxy group, approximately 17 of the companies have growth rate estimates that exceed the long-term projected growth of U.S. GDP. On average, his proxy group growth rate is 6.01%.

I explained above that both practitioners and academics support the notion that long-term sustainable growth cannot be greater than the economy in which the company sells its good and services. Growth can exceed the service area economic growth over short periods of time, but over the long-term the expectation that the growth will exceed the economy in which it sells its services is not rational nor reasonable. Because Dr. Vander Weide's growth rates exceed the long-term expected growth of the U.S. GDP, his DCF return estimate is unreasonable and should be rejected.

Q IS A QUARTERLY COMPOUNDING ADJUSTMENT TO A DCF RETURN ESTIMATE REASONABLE?

A No. Including the quarterly compounding adjustment to Gulf Power's authorized return on equity is inappropriate. If a quarterly compounding adjustment is added to a DCF return estimate, shareholders will be permitted to earn the dividend reinvestment return twice: (1) through the higher authorized return on equity, and (2) through actual receipt of dividends and the reinvestment of those dividends throughout the year. This double counting of the dividend reinvestment return is not reasonable and will unjustly inflate Gulf Power's rates.

Q PLEASE EXPLAIN WHY THE QUARTERLY COMPOUNDING RETURN SHOULD NOT BE INCLUDED IN GULF POWER'S AUTHORIZED RETURN ON EQUITY.

A Simply put, the quarterly compounding component of the return is not a cost to the utility. Only the utility's cost of common equity capital should be included in the authorized return on equity.

This issue surrounds whether or not the DCF return estimate should include the expectations by investors that they will receive cash flows within the year, that can be reinvested in other investments of comparable risk, and thus the cash flows will produce compounded returns throughout the year. The relevant issue for setting rates is whether or not that reinvestment return <u>is a cost to the utility</u>. It is not!

The reinvestment return is not a cost to the utility and therefore should not be included in the authorized return on equity. While it is reasonable for investors to expect to have the opportunity to earn the compounded return produced by cash flows received within the year, the compound return is not paid to investors by the utility.

Q CAN YOU PROVIDE AN EXAMPLE OF WHY THE COMPOUNDING RETURN ESTIMATE IS NOT A COST TO THE UTILITY?

A Yes. I will provide two examples to help illustrate this point. First, consider the cost to the utility of an outstanding utility bond. Most utility bonds pay a coupon every six months. The utility annual cost paid to the bond investor is the sum of the two semi-annual coupon payments. A bond investor expects to receive the semi-annual coupon payments from the utility, but also has an opportunity to reinvest the first coupon payment for the remaining six months of the year to enhance his end-of-year return. This compound return component is, however, not a cost to the utility because the utility does not pay the extra return.

For example, assume Gulf Power has an outstanding bond with a face value of $1,000, at an interest rate of 6% which is paid in two semi-annual $30 coupon payments. Gulf Power's cost of this bond is 6%. This 6% cost to Gulf Power is based on a $30 coupon payment paid in month 6 and month 12 for an annual payment of $60 relative to the $1,000 face value of the bond. However, the bond investor would have an annual expected return on this bond of 6.1%. This annual expected return would be realized by receiving the first $30 semi-annual coupon payment from Gulf Power and reinvesting it for the remaining six months of the year. This would produce $0.89 of semi-annual compounding return (\$30 x [$(1.06)^{1/2}$ - 1]). Hence, the bond investor would receive \$60 from Gulf Power, and \$0.89 from investing the first coupon for a total annual return of 6.09%, or 6.1%.

Importantly, if Gulf Power were to recover a 6.1% cost of this bond in its cost of service, and paid that return out to the bond investor, then the bond investor would receive \$60.89 from Gulf Power, rather than the \$60.00 actual cost, but the bond investor could still reinvest the semi-annual coupon, now \$30.89 for the remaining six months of the year. This would provide the investor with the reinvestment return twice, once from utility ratepayers, and a second time after the semi-annual coupon payment was paid and reinvested.

Reflecting this compounding assumption in the authorized return on equity therefore will double count the reinvestment return opportunity.

Q DOES THIS EXAMPLE ALSO APPLY TO UTILITY STOCK INVESTMENTS?

A Yes. Assume now that an investor purchased Gulf Power stock for \$100, and expects to receive four quarterly dividends of \$1.50, or \$6.00 per year. The expected cost to the utility of this dividend payment over the year would be \$6.00, or 6.0%. However, the expected effective yield of the dividend to investors would be 6.13% because the quarterly dividends could be reinvested for the remaining term of the year. Hence, the expected end-of-year value of those four \$1.50 quarterly dividend payments to the investor would be \$6.13.[25] Again, the utility pays \$6.00 of annual dividends. The \$0.13 is not paid to investors from the utility, but is rather earned in the other investments that earn the same return, which the dividends were invested in throughout the year.

[25] $1.5 \times (1.06)^{.75} + 1.5 \times (1.06)^{.5} + 1.5 \times (1.06)^{.25} + 1.5 = \$6.13$.

Importantly, the reinvestment return of the dividends is not paid by the utility, and therefore is not part of the utility's cost of capital. Again, if this dividend reinvestment return is included in the utility's authorized return on equity, then investors will receive the dividend reinvestment return twice, once through the authorized return on equity, and a second time when dividends are actually received by investors and reinvested.

Q CAN DR. VANDER WEIDE'S DCF ANALYSIS BE USED TO PRODUCE A RELIABLE DCF RETURN FOR GULF POWER IN THIS CASE?

A Yes. Reflecting a period of abnormally high short-term growth, followed by a decline to long-term sustainable growth, removing his quarterly compounding assumption, and excluding his flotation cost adjustment, the data used by Dr. Vander Weide in his DCF study can produce a reasonable return estimate for Gulf Power.

Q WHAT RETURN ON EQUITY WOULD DR. VANDER WEIDE'S DCF DATA SUGGEST IS APPROPRIATE FOR GULF POWER IN THIS CASE.

A I apply a multi-stage DCF model to Dr. Vander Weide's utility proxy group. In this analysis, I used the average of his four growth rate estimates for the first growth stage (includes the period from year 1 to year 5); the second stage is the transition stage from year 6 to year 10; and for the third growth rate stage, which starts in year 11 to perpetuity, I used the projected average 5- to 10-year GDP growth rate of 4.9%.

Applying the multi-stage DCF version to Dr. Vander Weide's utility group yields average and median DCF returns of 10.09% and 10.14%, respectively, as shown in Exhibit MPG-18.

Q **PLEASE DESCRIBE DR. VANDER WEIDE'S EX ANTE RISK PREMIUM METHODOLOGY.**

A Dr. Vander Weide estimated a DCF return on a proxy group of electric companies relative to the utility bond yield with a rating of "A." He performed this analysis for a period from September 1999 through December 2010. Based on this study, Dr. Vander Weide asserts that his risk premium estimate was 4.9% for this historical period based on prospective DCF return estimates relative to bond yields.

To this estimated market risk premium of 4.9%, he added a projected "A" rated Moody's bond utility yield of 6.15%. He then concluded that this produced a return on common equity of 11.0%.

Q **PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VANDER WEIDE'S EX ANTE RISK PREMIUM ANALYSIS.**

A I believe Dr. Vander Weide's estimated market risk premium from his ex post risk premium study represents a very high-end estimate of an appropriate risk premium for this proceeding. However, because bond yields are relatively low currently, it can be used to produce a reasonable return on equity estimate for Gulf Power. Hence, applying his estimate of a 4.9% equity risk premium, to the current observable "A" rated utility bond yield of 4.92%, produces a return on equity for Gulf Power of 9.82% in this proceeding.

Q **PLEASE DESCRIBE DR. VANDER WEIDE'S EX POST RISK PREMIUM METHODOLOGY.**

A In Dr. Vander Weide's ex post methodology, he compared the historical realized return on the S&P 500 relative to estimated changes in bond price for an "A" rated utility bond. He performed a second ex post risk premium analysis comparing the historical achieved return on the S&P Utility Index, relative again to changes in "A" rated utility bond yields.

Based on this analysis, Dr. Vander Weide estimates an equity risk premium in the range of 4.64% (based on S&P 500) to 4.1% (based on utility yields). He then applies this estimated equity risk premium to his projected "A" rated utility bond yield of 6.15% to produce an estimated equity risk premium in the range of 10.2% to 10.8% as outlined at page 38 of his testimony. He then added 26 basis points for a flotation cost, and proposes a point estimate for his risk premium study of 10.8%.

Q **DO YOU BELIEVE THAT DR. VANDER WEIDE'S EX POST RISK PREMIUM RECOMMENDATION IS REASONABLE?**

A No, for several reasons. First, his projected "A" rated utility bond yield of 6.15% substantially exceeds current observable utility bond yields of 4.92%. While these bond yields are low, Dr. Vander Weide's projected yield is abnormally high. Reflecting just the high-end of his estimated equity risk premium using his ex post risk premium study of 4.6%, with current bond yields of 4.92%, would indicate a fair return on equity for Gulf Power in this case of 9.52%. Using his low-end estimate of 4.1%, would indicate a return on equity of 9.02%. As such, Dr. Vander Weide's recommended return on equity with this methodology substantially overstates current observable market costs.

Q PLEASE DESCRIBE DR. VANDER WEIDE'S CAPM STUDIES.

A Dr. Vander Weide performed a historical DCF study based on a market risk premium of 6.7%, a risk-free rate of 4.5%, and beta estimate of 0.67. This study produced a return on equity estimate of 8.94%. He then added 26 basis points for flotation cost to produce a historical CAPM return estimate of 9.2% (page 41). He also performed a DCF-based CAPM study, where he estimated the market risk premium using a DCF return on the S&P 500. Based on that study, Dr. Vander Weide estimated a market risk premium of 8.85%, and use of his risk-free rate of 4.45%, and beta estimate of 0.67, produced a CAPM return estimate of 10.44%. He then added his 26 basis point flotation cost adjustment to this return to produce a CAPM return estimate of 10.7% (page 46).

Q DO YOU HAVE ANY CONCERNS WITH DR. VANDER WEIDE'S HISTORICAL CAPM RETURN ESTIMATE?

A No, but I do believe for the reasons set forth above, his proposal to include a 26 basis point flotation cost adjustment is not just nor reasonable. Therefore, it should be rejected.

Q DO YOU HAVE ANY CONCERNS WITH DR. VANDER WEIDE'S DCF-BASED CAPM RETURN ESTIMATE?

A Yes. I believe his market risk premium of 8.85% is overstated because it reflects an excessive projected return on the market. Therefore, I believe this CAPM return estimate should be rejected.

Q PLEASE DESCRIBE DR. VANDER WEIDE'S DCF-BASED CAPM ANALYSIS.

A Dr. Vander Weide estimates a forward-looking return on the market of 13.3%. From this market return estimate he subtracts his risk-free rate, a long-term Treasury bond yield of 4.45%. From this he produced a market risk premium of 8.85% (13.3% less 4.45%). He relies on a beta of 0.67, risk-free rate of 4.45%, and market risk premium of 8.85% to produce a bare bones CAPM of 10.4%. He then adds a 0.26% flotation cost adjustment to produce a 10.7% DCF-based CAPM estimate. (Vander Weide Direct at 46 and Schedule 8).

Q IS DR. VANDER WEIDE'S DCF-BASED CAPM ESTIMATE REASONABLE?

A No. Dr. Vander Weide's DCF-based CAPM analysis is based on a market risk premium of 8.85%. As discussed in my CAPM analysis, that market risk premium is significantly higher than the historical market risk premium of 6.7%. Dr. Vander Weide's 13.3% DCF market return used to derive the market risk premium of 8.85% is highly inflated and unreliable. This market return estimate is based on a DCF analysis that includes a growth rate projection of around 10.8% and a dividend yield of 2.5%. Dr. Vander Weide's risk premium is dramatically overstated because it is based on a DCF return produced by irrationally high growth outlooks, and is, therefore, not reliable.

More specifically, it is simply irrational to expect that securities market capital appreciation and growth will be above 10.0% for an indefinite period of time. This is important because the DCF model requires a sustainable long-term growth rate, not simply a growth rate that might be appropriate for the next five years. The growth rate for the overall securities market must reflect the economy in which its companies operate, and the earnings and dividend-paying ability of those companies. Companies produce earnings and dividends by selling goods and services in the marketplace. Hence, companies' earnings growth and sales growth opportunities cannot be substantially in excess of the expected growth in the overall economy. It is simply not a rational expectation to believe that, for an extended period of time, the growth rate of companies will both exceed the growth of the overall economy in which they sell their goods and services and produce earnings to pay dividends. As I mentioned above, *Blue Chip Financial Forecasts* projects an average 5- to 10-year nominal growth in the GDP, or overall U.S. economy, of 4.9%.[26] Hence, expecting a growth rate of 10.6%, in essence, assumes that the securities market can grow at a rate almost twice that of the overall U.S. economy. This is simply not a rational expectation.

CPRO PARAMETERS

Q HAVE YOU REVIEWED THE PROPOSED CPRO PROPOSED BY GULF POWER?

A Yes. Gulf Power witness James I. Thompson (Direct at page 14) outlines the Company's proposal for a new critical peak rate option for medium and large-sized business customers. The CPRO is available with the General Demand Service ("GSDT") and Large Power Service Time-of-Use ("LPT") rates. The CPRO provides customers the opportunity to reduce their demand costs if they can reduce their load during critical peak periods.

Under the CPRO, demand charges for customers would be broken into three parts instead of two. During non-critical peak periods, customers would pay a maximum demand charge and an on-peak demand charge. If a critical

[26] *Blue Chip Economic Indicators*, March 10, 2011.

peak period is called, customers would also be billed a critical peak period demand charge. If customers can reduce demand when a critical peak is called, they can avoid this CPRO demand rate. If customers have flexibility, the availability of this critical peak charge will allow them to reduce their overall demand cost relative to the Company's standard tariff rate options.

Q ARE THERE BENEFITS TO A CPRO PROGRAM?

A Yes, several. The CPRO can help reduce Gulf Power's system demand during critical peaks. This may allow the Company to avoid high-cost power generation, high-cost purchases, and/or defer the development of new generation units to meet peak demand.

Customers that have the load flexibility can also use the CPRO rate to reduce cost and improve their competitiveness in their own markets. As such, the CPRO rate can help to retain and attract businesses to Gulf Power's service territory and support the local economies. Finally, the CPRO is a tariff-based demand response type program, which generally is consistent with the policy objectives of Florida to create more power efficiencies and reduce peak demands.[27]

[27]Gulf Power is subject to the Florida Energy Efficiency and Conservation Act ("FEECA") and is currently working toward its conservation goals approved by the Florida Public Service Commission ("PSC") in Order No. PSC-09-0855-FOF-EG. Its 2012 goal is to reduce commercial/industrial summer and winter peaks by 2.1 MW and 0.8 MW, respectively.

Q **DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE CPRO FOR GSDT AND LPT CUSTOMERS?**

A Yes. I am proposing three adjustments that should serve to increase customer participation on this rate. My three adjustments are as follows:

1. The CPRO tariff language should further clarify when a critical peak can be declared.
2. The tariff should clearly define the allowed frequency of critical peak periods.
3. The tariff applicability should be modified so customers can place less than their full load on this rate. Customers should be allowed to designate a portion of their load as firm, and place a portion on the CPRO rate.

Q **UNDER THE PROPOSED CPRO TARIFF, WHEN CAN A CRITICAL PEAK EVENT BE DECLARED?**

A In the Company's proposed tariff, a critical peak may be designated at any time at the Company's discretion. No further explanation is provided in the tariff.

Q **DID THE COMPANY PROVIDE ANY FURTHER EXPLANATION OF WHEN CRITICAL PEAK PERIODS MAY BE DESIGNATED?**

A Yes, but only in a discovery request. In the Company's response to Staff's First Set of Interrogatories, question #19, the Company listed three indicators that would be used to determine when a critical peak event will be called. Those indicators include the following:

1. Forecasted temperatures above (summer) or below (winter) certain thresholds;
2. Market real-time-price thresholds; and
3. When Gulf Power's system control personnel project a system load peak is probable.

Q WOULD THESE PARAMETERS BE MORE APPROPRIATE FOR INCLUSION IN THE CPRO TARIFF FOR DESIGNATION OF WHEN A CRITICAL PEAK PERIOD CAN BE DECLARED BY THE COMPANY?

A Yes. Transparency with regard to when Gulf Power can declare a critical peak event will assist customers on the CPRO tariff to anticipate when critical peak periods will be declared and to prepare for them. Providing customers clear CPRO guidelines will permit them to form outlooks on critical peak frequency and will allow the implementation of procedures that will allow them to comply with CPRO declarations and minimize their compliance costs.

For these reasons, I believe the three factors identified by the Company in response to a Staff data request, and as currently being used for designation of critical pricing periods in the Company's Rate Schedule RSVP, should be more clearly specified to provide CPRO customers clear transparency of when critical peak periods will occur.

Toward this objective, I recommend the Company identify the forecasted temperatures for summer and winter periods, identify market clearing price thresholds which can trigger a critical peak period, and provide guidance to customers when its control personnel may project a system peak load to be probable. These factors should be included in the CPRO so customers electing this rate option can plan for critical peak events.

Q UNDER THE CPRO, DOES THE COMPANY STATE HOW MUCH OF THE CUSTOMER'S LOAD MUST BE PLACED ON THE CPRO TARIFF?

A Yes. Under the applicability provisions of the tariff, Gulf Power requires that on an annual basis, customers place their entire electrical requirements on the CPRO tariff.

Q DO YOU BELIEVE THAT THE CPRO TARIFF SHOULD BE MODIFIED TO ALLOW CUSTOMERS TO TAKE A PORTION OF THEIR LOAD UNDER A STANDARD TARIFF, AND PLACE A PORTION OF IT ON THE CPRO OPTION?

A Yes. Gulf Power should be able to depend on the load enrolled on the CPRO tariff as a resource to help manage load during critical peak periods. Some customers may be interested in participating in the CPRO program, but may not be able to offer all of their load due to plant minimum requirements, safety issues or economic restrictions on the cost/benefit of CPRO. Allowing them to offer only a portion of their load into a CPRO program would provide better information to Gulf Power about how much load is potentially available for curtailment in response to a critical peak event. And, because of this more flexible option, Gulf Power may have more load offered into a critical peak curtailment program than might otherwise be available.

Q **UNDER THE CPRO TARIFF, HOW OFTEN CAN A CRITICAL PEAK BE DECLARED?**

A Under the tariff option, the Company states that the duration of any single critical peak period may range from one to two hours in length, and the total number of hours designated as critical peak periods may not exceed 87 hours per year.

Q **DO YOU BELIEVE THE COMPANY HAS PROVIDED ENOUGH LIMITATIONS IN THESE CRITICAL PEAK DESIGNATIONS?**

A No. I believe some further restrictions should be included in the designation of critical peaks. For example, those may include the following:

1. Only one critical peak period may be called on any given day.
2. No more than four critical peak events can be called in a given week.

The critical peak frequency and duration periods should comply with load studies by Gulf Power to help ensure this rate can be used as a supply-side resource to balance supply and demand during critical peak periods.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

Qualifications of Michael P. Gorman

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Managing Principal with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. ("BAI") was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

BY MAJOR THOMPSON:

Q. And you have exhibits that have been marked 66 to 83. Do you have any changes or corrections to those?

A. I do not.

Q. Could you provide a brief summary of your testimony?

A. Yes. Good morning, Mr. Chairman and Commissioners. My testimony concerns the fair rate of return for Gulf Power Company. The rate of return is composed of an appropriate capital structure, embedded cost of debt and preferred equity, and a fair return on common equity.

In my testimony, I originally took issue with the company's proposed capital structure because I believed they did not properly state the amount of deferred taxes included in that capital structure. However, based on the company's rebuttal testimony, I withdraw the proposed adjustments and no longer take issue with the company's proposed capital structure.

I did not take issue with the company's estimated embedded cost of debt or preferred equity. My recommended return on common equity for the company is the 9.75 percent.

I evaluated that common equity return by first reviewing the investment characteristics of the utility industry and the investment risks and characteristics of Gulf Power in particular. Based on that assessment, I believe the utility industry is perceived by investors as a low-risk, safe haven investment, which is corroborated by comments and assessments made by credit rating analysts reviewing credit rating standings of utility companies.

I next performed three market-based analyses to estimate the current market cost of equity for Gulf Power.

I first did a discounted cash flow study using three variations of the model to try to properly capture the growth rate, which is typically the most controversial aspect of a DCF study, to more accurately estimate what the market's cost of equity is for a utility with the investment characteristics of Gulf Power.

I performed a constant growth DCF study using the analysts' three- to five-year growth rate estimates. The constant growth model requires growth rate estimates that can be sustained indefinitely. Unfortunately, analysts don't publish long-term expected growth rates for the utility industry; therefore, I had to use the short-term growth rates as a proxy for long-term growth rate outlooks.

Because they are growth rates projected over the next three to five years and not over the indefinite horizon, I also reviewed whether or not the three- to five-year growth rate estimates projected by analysts are reasonable estimates of what a rational investor could expect to be sustained in the long term. Based on that evaluation, I found that the three- to five-year growth rate projections of analysts are slightly higher than what I believe to be rational estimates of long-term sustainable growth.

Because of that finding, I also performed a constant growth DCF analysis which looks at the amount of earnings that can be reinvested in the company to sustain indefinitely a level of growth for a utility company. I also looked at a multi-stage growth discounted cash flow study which is capable of projecting the expectations that utilities will have abnormally high periods of growth over the short term, but eventually the growth will recede to a more lower level sustainable growth rate outlook.

Each of these DCF models produced reasonably consistent results. And based on my constant growth DCF model, I estimate a fair return on equity for Gulf Power of 9.75 percent.

I also performed a risk premium study. A risk premium study looks at observable real bond yields in the marketplace, and I add to that an equity risk premium that captures the difference in risk between a utility bond investment and a utility equity investment. I also did a risk premium by estimating what an appropriate risk premium would be for a utility equity investment relative to a Treasury bond investment. Using that analysis, I also estimated a return on equity for Gulf Power in this case of 9.75 percent. The risk premium in that instance I think corroborated the results of my DCF study.

I also performed a capital asset pricing model. This model estimates an expected return on the market, converts that into an expected risk premium on the market, and then with the use of a systematic risk component, which is characteristics of the investment risk of a utility company, I adjusted the market risk premium down to an appropriate risk premium for a lower than market risk utility company. Using that methodology, I estimated a return on equity for Gulf Power of 9.0 percent.

In my recommended return on equity for Gulf Power, I relied predominantly on my DCF and risk premium study. I am somewhat concerned about the CAPM analysis at this time, largely because the risk-free rate proxy or the Treasury bond yield is at abnormally low levels. I thought it conservative then to place minimal to no weight on my CAPM return estimate and support my return on equity recommendations based on the results of my DCF and risk premium studies.

After I estimated what I thought to be a fair return on common equity for Gulf Power based on its current investment risk, I then tested whether or not that return on equity that would support credit metrics that would support an investment grade bond rating. The standards for a fair return, as I understand them, are both fair compensation based on the returns investors could expect to earn on other investments of comparable risk, but also a return which will maintain the financial integrity of the utility.

CHAIRMAN GRAHAM: Mr. Ramas, your five-minute summation is up. Can you wrap up in about 30 seconds?

THE WITNESS: Yes. Based on the financial integrity assessment, my return on equity of 9.75 percent is fair and will maintain financial integrity.

I also responded to the company's return on equity of 11.7 percent, found significant flaws in the company's DCF and risk premium studies, and I concluded that the leverage adjustment, which added about 90 basis points to the company's return on equity, to be flawed and unreliable and generally inconsistent with what regulatory commissions typically will rely on to support a fair return on equity for a utility company.

Thank you.

MAJOR THOMPSON: I would like to make Mr. Gorman available for cross.

CHAIRMAN GRAHAM: Thank you. Intervenors that are of a different point of view?

Staff?

MR. YOUNG: No cross.

CHAIRMAN GRAHAM: Board? Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I just have one question.

You're recommending a return on equity of 9.75; correct?

THE WITNESS: Yes.

COMMISSIONER BALBIS: And Gulf's current return on equity is, I believe, 11.75; is that correct?

THE WITNESS: The current authorized return on equity was several years ago. I believe that's correct. I would have to double-check.

COMMISSIONER BALBIS: Did you look at similar companies that had a return on equity of 9.75 that you recommended?

THE WITNESS: Well, I looked at companies that have comparable investment risk, and I estimated what investors are currently demanding in terms of return to make investments in those companies. And capital market costs will move over time, so what I attempted to do was measure the rate of return that an investor would demand of the company in order to make an investment, which is the underlying basis for my contention that my return on equity of 9.75 represents fair compensation to Gulf Power.

COMMISSIONER BALBIS: Okay. So -- and I guess just to simplify it more, for companies of similar risk that have a 9.75 or near a 9.75 return on common equity, do they have difficulty accessing capital with that return on equity?

THE WITNESS: Well, that's a very good question. Authorized returns on equity have been coming down for the last two or three years. In 2011, through the first three quarters of this year, the average return on equity for an electric utility company was right about 10 percent, 10.1 percent.

That was skewed up somewhat in the first quarter when Virginia awarded a 12.3 percent return on equity to Virginia Electric Power Company, but that return was dedicated to a specific generating facility only, not the overall integrated utility company.

If you pull those out of the first quarter, very consistently, authorized returns on equity for this year have been about 10 to 10.1 percent. But the trend has been down. And the reason the trend has been down is because capital market costs for utility companies has been declining over that time.

At the beginning of 2011, as an example -- and this is an observable example of what the utilities' cost of capital is. In the beginning of the year, an A-rated utility bond yield was about 5.5 percent. Currently they're less than 5 percent. So that indicates the cost of capital for a utility has declined throughout 2011. We're seeing that in authorized returns on equity.

But the industry averages are higher than what I'm recommending, but importantly, investors understand that if a utility's authorized return on equity is tied to what the current market cost of capital is for that utility, then investors can have some confidence that the integrity of the utility will be preserved, because capital market costs don't just go down; they eventually could go back up.

So if investors want the authorized return on equity to go up when cost of capital increases, then it's reasonable for them to expect that the authorized return on equity will go down when capital market costs decrease. So the expectation is to track the cost of capital for utilities.

But authorized returns on equity have been around 10 percent for electric utilities so far this year, and I'm a little bit less than that industry average.

COMMISSIONER BALBIS: Okay. Thank you. I have nothing further.

CHAIRMAN GRAHAM: Redirect?

MAJOR THOMPSON: No redirect, sir.

CHAIRMAN GRAHAM: Exhibits we need to enter into the record?

MAJOR THOMPSON: Mr. Chairman, I would ask that Exhibits 66 through 83 be put into the record.

CHAIRMAN GRAHAM: Sixty-six, 67, 68, 69, 70, '1, '2, '3, '4, '5, '6, '7, '8, and at the top of page 14, 79, 80, 81, 82, and 83 will all be entered into the record.

(Exhibit Numbers 66 through 83 were admitted into the record.)

MAJOR THOMPSON: Thank you.

CHAIRMAN GRAHAM: Okay. Any other exhibits? None?

MAJOR THOMPSON: No, sir.

CHAIRMAN GRAHAM: Okay. Sir, thank you.

THE WITNESS: Thank you.

MR. McGLOTHLIN: OPC calls Donna Ramas.

While Ms. Ramas is taking her seat, Mr. Sayler is going distribute the errata for all of our witnesses at this point.

Thereupon,

DONNA RAMAS

was called as a witness on behalf of the Citizens of the State of Florida and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q. Ms. Ramas, have you been sworn?

A. Yes, I have.

Q. Please state your name and business address for the record.

A. My name is Donna Ramas, and I'm employed by the firm Larkin & Associates. The address is 15728 Farmington Road, Livonia, Michigan.

Q. What is your position with Larkin & Associates?

A. I'm a senior regulatory analyst with the firm.

Q. Ms. Ramas, at our request, did you prepare and submit prefiled testimony for the Office of Public Counsel in this case?

A. Yes, I did.

Q. Do you have before you the document that was dated October 14, 2011, captioned "Direct Testimony of Donna Ramas, CPA"?

A. Yes, I do.

Q. Do you have any changes or corrections or additions to make to that document?

A. I don't have any corrections. However, I do wish to point out several items that have changed since the time I calculated the revenue requirements presented within this testimony.

The first item that has changed is that based on a review of the information filed by Gulf with its rebuttal testimonies, I am now satisfied that the amount of plant additions included in the case associated with the Smart Grid Investment Grant program is limited to

Gulf's portion of the project costs and specifically excludes the amount that's being funded through the Department of Energy grant. Therefore, I'm no longer recommending that those items be removed from rate base.

The second item that changed is that since the time my prefiled direct testimony was filed, the revenue requirement impacts of the movement of the Crist Unit 6 and 7 turbine upgrade projects have been moved from the environmental cost recovery clause into base rates, so the impact of that movement was discussed in my supplemental testimony. It's not included in the revenue requirements presented in my direct testimony.

The final area that would change is that there have been several stipulations in this case, and the revenue requirement impact of those stipulations aren't included in my prefiled direct testimony.

Q. With that explanation of changes that have occurred since you filed your testimony, do you adopt the questions and answers contained in the October 14th document as your testimony today?

A. Yes, I do.

Q. And did you prepare exhibits to your direct testimony of October 14th?

A. Yes, I did.

MR. McGLOTHLIN: Commissioners, those have been identified as Exhibits 35 and 36.

BY MR. McGLOTHLIN:

Q. Ms. Ramas, do you also have before you a second document dated November 15, 2011, captioned "Supplemental Direct Testimony of Donna Ramas, CPA"?

A. Yes. Yes, I do.

Q. And did you prepare and submit that on behalf of OPC in this case?

A. Yes, I did.

Q. Do you have any changes, corrections, or additions to that document?

A. No, I do not.

Q. If I were to ask you the questions that are contained in this document, would your answers be as reflected there?

A. Yes, they would be the same.

Q. So do you adopt this document as your testimony today?

A. Yes, I do.

MR. McGLOTHLIN: I ask that the direct testimony of Donna Ramas dated October 14, 2011, and the supplemental direct testimony of Donna Ramas dated November 15, 2011, be inserted at this point as though read.

CHAIRMAN GRAHAM: We will enter Ms. Ramas's direct and supplemental direct testimony into the record as though read.

DIRECT TESTIMONY
OF

DONNA RAMAS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 110138-EI

INTRODUCTION

Q. **WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?**

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. **PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.**

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?**

A. Yes, I have testified before the Florida Public Service Commission on several prior occasions. I have also testified before several other state regulatory commissions.

Q. **HAVE YOU PREVIOUSLY PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?**

A. Yes. I have attached Exhibit__(DR-2), which is a summary of my regulatory experience and qualifications.

Q. **ON WHOSE BEHALF ARE YOU APPEARING?**

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC") to review the rate request of Gulf Power Company ("Gulf" or "Company"). Accordingly, I am appearing on behalf of the Citizens of the State of Florida ("Citizens").

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

A. I am presenting the OPC's overall recommended revenue requirement in this case. I also sponsor several adjustments to the Company's proposed rate base and operating income, and discuss the deferred income tax component of the capital structure.

Q. **ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?**

A. Yes. Helmuth W. Schultz, III, also of Larkin & Associates, PLLC, is presenting testimony. Kimberly Dismukes and Dr. Randy Woolridge are also presenting testimony.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first present the overall financial summary, presenting the overall revenue requirement recommended by Citizens in this case. The overall financial summary presents the results of the recommendations of each of the Citizens witnesses in this case. I then address various adjustments I am sponsoring in this proceeding, followed by a discussion of the deferred tax component of the capital structure.

<u>OVERALL FINANCIAL SUMMARY</u>

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I have prepared Exhibit__(DR-1), consisting of Schedules A, A-1, B-1 through B-3, C-1 through C-8 and D. The schedules presented in Exhibit__(DR-1) are also consecutively numbered at the bottom of each page.

Q. WHAT DOES SCHEDULE A, TITLED "REVENUE REQUIREMENT" PRESENT?

A. Schedule A presents the revenue requirement calculation, at this time, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens' witnesses Schultz, Dismukes and Woolridge. The calculation of the net operating income multiplier (or gross revenue conversion factor) is presented on my Schedule A-1. The adjustments presented on Schedule A which impact rate base can be found on Schedule B-1. Schedules B-2 and B-3 provide supporting calculations for rate base adjustments I am sponsoring, which are presented on Schedule B-1. The OPC adjustments to net operating income are listed on Schedule C-1.

Schedules C-2 through C-8 provide supporting calculations for the adjustments I am sponsoring to net operating income, which are presented on Schedule C-1.

Q. WOULD YOU PLEASE BRIEFLY DISCUSS SCHEDULE D?

A. Schedule D presents Citizens' recommended capital structure and overall rate of return based on the recommendations of Citizens' witness Dr. Woolridge. The capital structure ratios are based on the ratios recommended by Dr. Woolridge; however, the capital structure dollar amounts differ as I have applied the adjustments to the capital structure necessary to synchronize Citizens' recommended rate base with the overall capital structure. On Schedule D, I then applied Dr. Woolridge's recommended cost rates to the recommended capital ratios, resulting in Dr. Woolridge's overall recommended rate of return of 5.89%.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR GULF POWER COMPANY?

A. As shown on Schedule A, the OPC's recommended adjustments in this case result in a revenue increase for Gulf Power Company of $11,812,000. This is $81.7 million less than the $93.5 million increase in base rates requested by Gulf in its filing.

<u>NET OPERATING INCOME MULTIPLIER</u>

Q. ARE YOU RECOMMENDING ANY MODIFICATIONS TO THE NET OPERATING INCOME MULTIPLIER PROPOSED BY THE COMPANY?

A. Yes, I am recommending a revision to the net operating income multiplier (i.e., gross revenue conversion factor) proposed by Gulf. In determining its proposed factor, Gulf included a bad debt rate of 0.3321%. Later in this testimony, under the heading of "Uncollectible Expense," I am proposing a bad debt rate for the 2012 projected test year of 0.3056%. On Schedule A-1, I replace the Company's proposed bad debt rate of 0.3321% with a more appropriate rate of 0.3056% in determining the net operating income multiplier. This revision results in a net operating income multiplier of 1.634173 as compared to Gulf's proposed multiplier of 1.634607. The revised multiplier is used in calculating the Citizens' proposed revenue deficiency on Schedule A.

<u>RECOMMENDED ADJUSTMENTS</u>

Q. **WOULD YOU PLEASE DISCUSS EACH OF THE ADJUSTMENTS TO GULF'S FILING YOU ARE SPONSORING?**

A. Yes, I will address each adjustment I am sponsoring below.

<u>Transmission Plant Additions</u>

Q. **WHAT LEVEL OF TRANSMISSION RELATED CAPITAL ADDITIONS HAS THE COMPANY BUDGETED FOR 2011 AND 2012?**

A. The Company budgeted transmission related capital additions of $66,748,000 for 2011 and $70,902,000 for 2012. The budgeted 2011 transmission capital additions of $66,748,000 includes $17,098,000 of transmission infrastructure replacement projects; $38,025,000 of transmission planning generated projects; $6,810,000 of distribution planning generated projects; and $4,815,000 of Smart Grid Investment Grant program projects. The 2012 budgeted transmission capital additions of $70,902,000 includes $6,180,000 of transmission infrastructure replacement projects; $56,107,000 of transmission planning generated projects; $2,975,000 of distribution planning generated projects; and $5.64 million associated with the Smart Grid Investment Grant program.

Q. **WHAT DIFFERENTIATES THE TRANSMISSION AND DISTRIBUTION PLANNING GENERATED PROJECTS FROM THE TRANSMISSION INFRASTRUCTURE REPLACEMENT PROJECTS?**

A. According to the testimony of Gulf witness P. Chris Caldwell, the transmission and distribution planning generated projects are the results of the transmission planning process which is described in his testimony. Under the transmission planning process, Gulf develops a 10-year plan that is based on load forecasting and other operational considerations. The 10-year plan is updated on an annual basis. According to Mr. Caldwell, the transmission planning process meets the North American Electric Reliability Corporation ("NERC") standards as well as the applicable Southeastern Electric Reliability Corporation ("SERC") standards. The projected 2011 and 2012 budgeted transmission capital additions in the transmission planning generated projects category are composed of a few large projects, such as the Smith-Laguna Beach-Santa Rosa transmission line and substation improvements, as well as the Slocomb-Holmes Creek-Highland City transmission line and substation improvements.

The transmission infrastructure replacement projects are for routine replacements of poles, transformers, voltage regulation equipment, switches, conductors and other assets. These would be the transmission capital expenditures for infrastructure replacement projects, but would not have been considered as part of the transmission planning process discussed above.

Q. YOU INDICATED THAT THE 2011 AND 2012 TRANSMISSION CAPITAL ADDITIONS BUDGET INCLUDED $4,815,000 AND $5,640,000, RESPECTIVELY, ASSOCIATED WITH THE SMART GRID INVESTMENT GRANT PROGRAM. WHAT IS THIS PROGRAM?

A. This program is discussed only briefly in Mr. Caldwell's testimony. Beginning at page 17 and continuing through page 18 of his testimony, Mr. Caldwell addresses the Smart Grid Investment Grant Program ("SGIG") projects that are included in the transmission capital additions budget as follows:

> As part of the American Recovery and Reinvestment Act, Congress allocated funding to the Department of Energy (DOE) for grants to increase the rate of Smart Grid equipment deployment across the United States. The transmission portion of this grant has been dedicated to replacing protection and control equipment in substations with new technologies which allow for better operation and control of the transmission network. These devices facilitate communication between remote field locations and the transmission control center as well as allowing more advanced protection schemes to be implemented throughout Gulf.

The amount addressed in Mr. Caldwell's testimony associated with the SGIG projects is limited to the transmission area. Other witnesses address the SGIG projects for which Gulf has budgeted in their respective testimonies. At page 27 of Gulf witness R. Scott Moore's testimony, he indicates that the Smart Grid Investment Grant is being conducted in conjunction with the Department of Energy and the Southern Company, or Gulf's parent company. Mr. Moore indicates that Gulf's capital investment dollars are matched by 50% with DOE SGIG funds.

Q. DO YOU HAVE ANY INFORMATION REGARDING THE AMOUNT OF THE SMART GRID INVESTMENT GRANT OR THE PORTION OF THAT GRANT THAT WILL APPLICABLE TO GULF'S OPERATIONS?

A. According to information available on Southern Company's website, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy in 2010 in which it accepted a $165 million award that will be used throughout the Company's four-state service territory over a three-year period. The website indicates that the federal funding will be matched by Southern Company and will allow for investment in the Company's transmission and distribution infrastructure. Based on the information I have been able to review to date, I was unable to determine how much of the $165 million grant from the Department of Energy would be allotted to the Gulf Power System. I was also unable to determine how Gulf has accounted for its allotment of the grant funds. However, the Company has identified some transmission and distribution related capital additions for the 2011 and 2012 budget period that would fall under this program.

Q. FOR THE SGIG PROJECTS INCLUDED IN GULF'S BUDGETED 2011 AND 2012 PLANT ADDITIONS IN THIS CASE, IS THE AMOUNT BASED ON THE TOTAL CAPITAL EXPENDITURES FOR THE PROJECT OR ONLY THE AMOUNT NET OF THE GRANT THAT WAS RECEIVED BY GULF'S PARENT, SOUTHERN COMPANY?

A. Based on the extremely limited information on the grant provided by the Company in its filing and supporting workpapers in this case, it appears that the capital additions budgets for 2011 and 2012 include the full projected capital expenditures for the SGIG projects. There is nothing in any of the witnesses' testimony in this case discussing the SGIG projects that indicates that the amount included is net of or excludes the portion that is being paid for with the grant from the Department of Energy.

Q. SHOULD THE SGIG PROJECTS INCORPORATED IN THE 2011 AND 2012 TRANSMISSION PLANT ADDITIONS IN THIS CASE REMAIN IN RATE BASE?

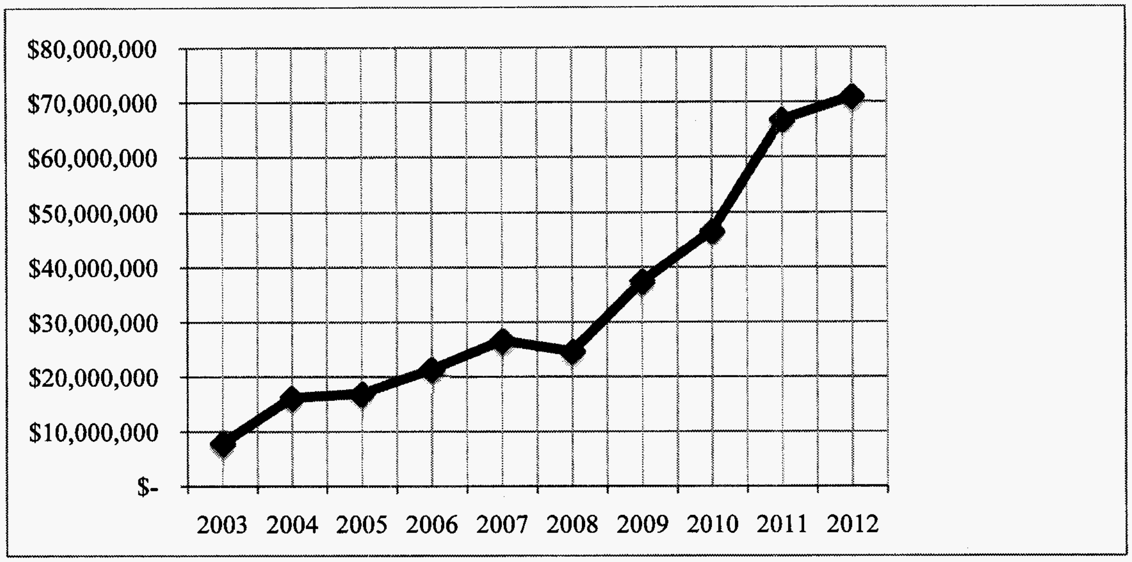
A. No. Presumably these projects would be at least partially covered by the DOE grant that was received by Southern Company; therefore, it would not be appropriate to charge the full cost of the project and incorporate those costs in rate base charged to customers. At this time I am recommending that the budgeted 2011 and 2012 transmission related Smart Grid Investment Grant project costs be excluded from rate base. I have removed the projected 2011 and 2012 SGIG grant program projects in the transmission area on Schedule B-2, page 1 of 3, line 4. This results in a $7,635,000 reduction to the projected 2012 test year average plant in service balances.

The Company's direct testimony in this case is silent on how those grants that are being received from the Department of Energy are being accounted for by Gulf in its rate case filing and the accounting treatment of these grants. If there are remaining areas of SGIG plant additions in this case (beyond those I am removing in this testimony) which Gulf has included in the balance for the capital additions in the 2012 average test year plant in service, those balances should also be removed. The benefit of the SGIG grant funding should be flowed to the ratepayers, and ratepayers should not be paying a return on investments that are being reimbursed in part to Gulf Power by the Department of Energy. The Commission routinely removes CIAC from rate base. In the case of the SGIG, the U.S. Taxpayer contributed these monies, and Gulf should not earn a return on these investments.

Q. HOW DO THE REMAINING NON-SGIG PROGRAM TRANSMISSION RELATED CAPITAL ADDITIONS THAT GULF HAS BUDGETED FOR 2011 AND 2012 COMPARE TO HISTORIC CAPITAL EXPENDITURES IN THE TRANSMISSION AREA?

A. The amount of transmission capital additions incorporated in its filing, excluding SGIG projects, are substantially higher than historic expenditure levels. The graph presented below shows the annual level of transmission related capital expenditures made by Gulf for each year, 2003 through 2010, as well as the budgeted transmission related capital expenditures for 2011 and 2012. As shown on the graph, the level of transmission-related capital expenditures sharply increased from 2008 to 2010, and is projected to have another substantial increase in annual expenditures in the 2011 and 2012 budget periods.

Gulf Transmission-Related Capital Expenditures
2003 – 2010 Actual and 2011/2012 Budgeted



Over the period 2003 through 2010, the average total transmission capital expenditures were $24,718,767. On Schedule B-2, page 2 of 3, I provide a breakout of the actual transmission related capital expenditures by cost type, such as infrastructure replacement projects and planning generated projects, for each year 2003 through 2010. The total amounts by transmission expenditure category for the period 2003 through 2010 equaled the amounts for each of these categories for that same period (2003 to 2010) that is presented on page 15 of Gulf witness P. Chris Caldwell's direct testimony in this case. As shown on Schedule B-2, page 2 of 3, the 2003 through 2010 average transmission capital expenditures of $24.7 million are similar to the $24.7 million level actually incurred by Gulf during 2008. As can also be seen from this table, the capital expenditures significantly increased by over 51% between 2008 and 2009, going from approximately $24.7 million to $37.4 million. The table also shows that between 2009 and 2010 the annual transmission related capital expenditures escalated another 24.74% to $46.6 million.

On page 3 of Schedule B-2, I present by transmission project type a comparison of the average 2003 through 2010 capital expenditures, the actual 2009 and actual 2010 capital expenditures, as well as the budgeted 2011 and budgeted 2012 transmission capital expenditures that are included in this case. As shown on this page, Gulf has projected that the 2010 expense level of $46.6 million will escalate substantially further to $66.7 million in 2011 and $70.9 million in 2012. Even if the Smart Grid Investment Grant program expenditures are excluded from the budgeted 2011 and 2012 amounts, there is still a substantial and sharp increase in the budgeted transmission related capital expenditures. In fact, the budgeted 2011 capital expenditures are 150.6% higher than the average level for the period 2003 through 2010, and the budgeted 2012 capital expenditures are 164% higher than that historic level. Also, excluding the SGIG projected expenditures, the budgeted 2011 and 2012 capital expenditures are 65.7% and 74.6%, respectively, higher than the actual 2009 expenditures.

Q. ARE YOU ABLE TO COMMENT ON WHAT IS CAUSING THE SHARP AND SIGNIFICANT INCREASE IN THE BUDGETED TRANSMISSION RELATED CAPITAL EXPENDITURES THAT IS INCORPORATED BY GULF IN THE MFRS?

A. A large portion of the sharp and significant increase in transmission capital expenditures is associated with the transmission planning generated projects category. The Company's workpapers show a few large transmission projects are budgeted for 2011, and Mr. Caldwell's testimony specifically references two other large transmission projects for 2012 (Caldwell, p.18). Since a large portion of the sharp and significant increase in transmission costs are tied to specific projects developed through Gulf Power's transmission planning generated projects process, at this time I am not recommending any adjustments associated with those specific transmission line projects in the transmission planning generated projects category.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE REMAINING PROJECTED TRANSMISSION CAPITAL EXPENDITURES THAT DO NOT FALL IN THE PLANNING GENERATED PROJECT CATEGORY?

A. Yes. Gulf has also budgeted for a sharp increase in the costs of the transmission infrastructure replacement projects in 2011. As shown on Schedule B-2, page 3 of 3, the average annual amount of transmission infrastructure replacement projects for the period 2003 through 2010 was $7,252,301. The Company has budgeted for 2011 that the infrastructure replacement projects in the transmission area will be $15,948,000, which is more than double the average historic level. During the historic period for which the average was calculated, 2003 through 2010, there were several hurricanes that impacted Gulf's service territory and would have resulted in a higher level of transmission replacement projects during that period. Thus, the 2003 through 2010 average historic replacement level of $7.3 million may be high compared to normal operating conditions. I am recommending that the budgeted 2011 and 2012 transmission infrastructure replacement project expenditures be reduced.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. As shown on Schedule B-2, page 1 of 3, I recommend that the budgeted 2011 and budgeted 2012 transmission infrastructure replacement projects be replaced with the average actual cost associated with these types of projects during the period 2003 through 2010. This recommendation results in an $8,695,699 reduction to the budgeted 2011 transmission capital additions and a $2.4 million increase in the 2012 level. As shown on page 1 of Schedule B-2, line 3, this results in a recommended reduction in the 2012 average test year plant in service balance of $7.5 million. In determining the amount of adjustment to plant in service, I have assumed that the projected 2012 expenditures are added evenly throughout the year.

Q. WHAT IS YOUR OVERALL RECOMMENDED ADJUSTMENT TO THE TRANSMISSION RELATED PLANT IN SERVICE IN THIS CASE?

A. As shown on Schedule B-2, page 1 of 3, line 5, I recommend that the transmission plant in service balance be reduced by $15,137,049. This is the result of reducing the 2011 transmission related capital additions by $13.51 million and reducing the 2012 capital additions by approximately $3.25 million, resulting in an impact on the average test year plant in service of $15.14 million. This adjustment removes the Smart Grid Investment Grant projects which should be at least partially funded by the DOE, as well as reduces the transmission infrastructure replacement projects down to an average historic level. Even larger adjustments may be warranted, given the significant spike in the transmission capital additions forecasted by Gulf Power in this rate case.

Q. WHAT IMPACT DOES YOUR RECOMMENDED REDUCTION TO TRANSMISSION RELATED PLANT IN SERVICE HAVE ON DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION?

A. As shown on Schedule B-2, page 1 of 3, transmission related depreciation expense incorporated in the test year should be reduced by $389,865 and accumulated depreciation should be reduced by $389,865, incorporating the average test year impact of the depreciation.

Q. HAVE YOU SEEN ANY INFORMATION THAT WOULD LEAD YOU TO BELIEVE THAT YOUR RECOMMENDED ADJUSTMENT IS CONSERVATIVE?

A. Yes. As part of its response to Citizens' First Request to Produce Documents, Question 12, the Company provided its capital budget variance report for the six month period ended June 2011. Based on the 2011 capital expenditure report, Gulf had budgeted for "Other transmission" projects of $37,963,984 for the first six-months of 2011. The actual year-to-date expenditures as of that date were $30,048,011. In other words, the other transmission related capital expenditures were $7,915,973 or 20.85% under budget by the mid-point of 2011. As shown on my Schedule B-2, page 1 of 3, I have recommended a $13.5 million reduction to the budgeted 2011 capital expenditures incorporated in the Company's filing. This adjustment is reasonable, particularly considering that the Company was already $7.9 million below its budgeted expenditures as of June 2011. The same capital expenditure report also shows that as of June 2011 Gulf's total power delivery capital expenditures, which would include both transmission and distribution, were $12,235,605 or 16.19% below budget. It is highly unlikely that the Company would make up by year end the full amount that it is under budget as of the mid-point of the current year.

Distribution Plant Additions – SGIG Projects

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO BUDGETED DISTRIBUTION CAPITAL ADDITIONS?

A. Yes. Gulf's budgeted capital additions include $1,980,000 in both 2011 and 2012 for distribution plant additions associated with the Smart Grid Investment Grant program projects. There is no indication in the testimony or workpapers on this issue that the amount excludes the portion funded through the grants. At this time, I recommend that these additions be excluded as at least partial funding for these projects would be provided for through the SGIG proceeds received by Southern Company from the DOE. As shown on Schedule B-3, removal of the distribution related SGIG projects incorporated in the distribution plant additions in this case results in a $2,970,000 reduction to average test year plant in service, a $103,915 reduction to test year depreciation expense based on the average distribution plant depreciation rate, and a $103,915 reduction to the average test year accumulated depreciation balance. As mentioned previously, additional adjustments may be needed to ensure that the projects funded with the grant proceeds are not included in Gulf's rate base in this case.

Construction Work in Progress

Q. HAS GULF INCLUDED CONSTRUCTION WORK IN PROGRESS ("CWIP") IN ITS RATE BASE REQUEST?

A. Yes. While Gulf has removed the CWIP associated with costs recovered through its various clauses and interest bearing CWIP that accrues an Allowance for Funds Used During Construction ("AFUDC"), the non-AFUDC CWIP remains in rate base. Gulf MFR B-1 shows that $62,617,000 ($60,912,000 jurisdictional) remains in rate base for CWIP.

Q. **IS THE CWIP THAT REMAINS IN RATE BASE A SUBSTANTIAL PORTION OF THE TOTAL PROJECTED TEST YEAR CWIP OR PLANT IN SERVICE BALANCES?**

A. No, it is not. The majority of Gulf's forecasted test year projects qualify for AFUDC accrual. In its filing, Gulf has removed $232,012,000 of interest bearing CWIP from its average test year CWIP balances. It has also removed $22,229,000 that is associated with projects that fall under the Environmental Cost Recovery Clause ("ECRC"). Thus, the non-interest bearing CWIP remaining after removal of the ECRC projects is only 19% of the total projected average test year CWIP balance. Gulf clearly is permitted to earn a return through AFUDC on the vast majority of its projected test year CWIP balances.

Q. **SHOULD THE COMMISSION ALLOW THE NON-INTEREST BEARING CWIP TO BE INCLUDED IN RATE BASE AS PROPOSED BY GULF?**

A. No, it should not. Construction Work in Progress, by its very nature, is plant that is not completed and is not providing service to customers. It is not used or useful in delivering electricity to Gulf's customers. Under the ratemaking process, utilities are permitted to earn a return on the assets that are used and useful in providing service to a utility's customers. Assets that are still undergoing construction clearly are not used in providing service to customers during the construction period. The ratemaking process in most jurisdictions therefore excludes CWIP from being included in rate base, requiring that assets be used and useful in serving customers prior to a return on those assets being recovered from ratepayers. As a general regulatory principle, CWIP should be excluded from rate base and excluded from costs being charged to customers until such time as it is providing service to those customers.

Additionally, the assets being constructed whose costs are included in CWIP are being built to serve both current customers and new customers that will be added to the system when the projects are completed. It is not appropriate to require current customers to pay a return on uncompleted assets that will also be used to serve customers that come on line after those assets are constructed and placed into service, particularly as the revenues from those future customers are not factored into the ratemaking process. Allowing inclusion of CWIP in rate base will result in a mismatch in the ratemaking process as some of those assets are being built to serve new customers yet the revenues from the future new customers are not included in the revenue requirement calculation during the period that the assets are being constructed.

Q. **DOES GULF ASSERT IN TESTIMONY THAT THE INCLUSION OF CWIP IN RATE BASE IS NECESSARY TO SHORE UP OR SAFEGUARD ITS FINANCIAL INTEGRITY?**

A. No.

Q. **WILL GULF'S FINANCIAL INTEGRITY BE NEGATIVELY IMPACTED IF THE NON-INTEREST BEARING CWIP IS EXCLUDED FROM RATE BASE?**

A. No, it should not. As previously mentioned, the majority of Gulf's projects included in the projected test year CWIP forecasts qualify for AFUDC. Less than 20% of the projected test year CWIP balances do not qualify for AFUDC. Excluding those non-AFUDC CWIP projects from rate base should have minimal impact on Gulf's financial integrity.

Q. **DOES COMMISSION RULE 25-6.0141 ON THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION DETERMINE WHETHER OR NOT PROJECTS ARE INCLUDED IN RATE BASE IN A RATE PROCEEDING?**

A. No, it does not. The rule allows that long-term construction projects, i.e., projects over a year in length, of a certain magnitude will accrue AFUDC and that shorter term projects will not. It also allows for special circumstances in which larger projects that would not normally qualify under the rule may accumulate AFUDC if desired by the Commission. The rule does not specify that non-AFUDC qualifying CWIP will be included in rate base in a rate case proceeding.

Short term projects that last less than one year will still provide the Company a return by either increasing sales or decreasing operating costs and therefore do not require an AFUDC return. Long-term projects may require the accrual of AFUDC because of the length of time it takes to complete the projects. However, the length of the project should not dictate whether or not that project that is not yet used and useful in serving customers is appropriate for inclusion in rate base.

Q. **HAVE YOU MADE AN ADJUSTMENT TO REMOVE THE REMAINING NON-INTEREST BEARING CWIP FROM RATE BASE?**

A. Yes, I have removed the remaining CWIP from rate base on Schedule B-1, page 2 of 2 for the reasons identified above. The primary reasons, however, are because ratepayers should not be charged a return on assets that are not yet completed and not yet being used to serve them, and Gulf has not demonstrated any justification for departing from this principle.

Uncollectible Expense

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE FILING FOR UNCOLLECTIBLE EXPENSE?

A. Gulf included $4,137,000 of uncollectible expense in its 2012 test year. The amount is based on a projected bad debt factor of 0.3321%, resulting in uncollectible expense of $4,343,000, which was then reduced by $206,000 to reflect projected reductions resulting from Gulf's anticipated increase in collection efforts. The Company also included the projected 0.3321% bad debt factor in determining its net operating income multiplier.

Q. IS THE 0.3321% BAD DEBT FACTOR USED BY GULF IN PROJECTING THE FUTURE RATE YEAR AMOUNT CONSISTENT WITH HISTORIC BAD DEBT RATES REALIZED BY GULF?

A. No, it is not. Gulf's MFR Schedule C-11 provided the bad debt factor, calculated as the net uncollectible write-offs to gross revenues from retail sales of electricity, for each year, 2007 through 2010. I have presented the bad debt factor and the amounts used by Gulf to calculate those factors, for each year 2007 through 2010 on Schedule C-2, attached to this testimony. As shown on the schedule, the bad debt factors vary from year to year and range from a low of 0.2804% to a high of 0.3323% in 2009. For the most recent calendar year of 2010, the year of the BP Oil Spill, the bad debt factor was 0.2937%, which is lower than the 2009 rate.

Q. HOW DID THE COMPANY DETERMINE ITS PROJECTED TEST YEAR FACTOR OF 0.3321%?

A. There is no explanation in Gulf's filing of how the factor was determined. The actual calculations of the projections for 2011 and 2012 presented in MFR Schedule C-11 were not provided, nor was any testimony provided describing how the amount was determined. Witness Erickson testifies about uncollectible accounts and provides Schedule 4 of CJE-1 to reflect the projected revenues, write-offs and bad debt factors for 2011 through 2015, but there is no support to show how the projections were made or what assumptions were used.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE PROJECTED AMOUNT OF UNCOLLECTIBLE EXPENSE AND THE PROJECTED BAD DEBT FACTOR?

A. Yes. As shown on Schedule C-2, the bad debt factor for Gulf varies from year to year. I recommend that Gulf's projected 2012 bad debt factor be replaced by the four-year average factor calculated using the years 2007 through 2010, resulting in a bad debt factor of 0.3056%. This is higher than the 2010 rate realized by Gulf of 0.2937%. As the level of bad debt expense to revenues varies from year to year, use of an average rate is appropriate to reflect a normalized level in rates going forward. As shown on Schedule C-2, replacing Gulf's proposed 0.3321% factor with my recommended factor of 0.3056% results in projected net write-offs of $3,997,000 which is a $346,000 reduction to the amount included in the filing. I am not removing the $206,000 uncollectable expense adjustment reflected by Gulf its filing as the reduction is projected to be the result of increased collection efforts that were not present in the historic period from which the uncollectibles rate is derived. As shown on Schedule A-1, I have also replaced Gulf's bad debt factor with my recommended bad debt factor for purposes of calculating the net operating income multiplier in this case.

Payroll Expense

Q. WHAT AMOUNT DID GULF INCORPORATED IN ITS FILING ASSOCIATED WITH PROPOSED INCREASES IN ITS EMPLOYEE COMPLEMENT?

A. As part of its filing, Gulf has projected a substantial increase in its employee complement. Gulf's filing includes the impact of its assumption that the actual December 31, 2010 employee count of 1,330 employees will increase by 159 employees to 1,489 employees by the start of the 2012 test year. This is a projected increase in the employee complement of 12% within a one year period (i.e., from December 31, 2010 to January 1, 2012).

Q. WHAT IMPACT DOES THIS PROJECTED 12% INCREASE IN THE EMPLOYEE COMPLEMENT HAVE ON TEST YEAR EXPENSES CONTAINED IN GULF'S RATE REQUEST?

A. Total projected 2012 base payroll costs include $7,765,817 for the 159 additional employees. Gulf has projected that much of these costs will be either capitalized or will be associated with the various rate clauses. Once the portion that is projected to be capitalized is removed, as well as the portion related to costs recovered through clauses and removed in the adjustments in Gulf's filing, $4,387,786 for base payroll associated with new positions remains in the adjusted test year expenses.

In addition to the base payroll costs, other costs are factored into Gulf's request associated with the 159 new employees. In its response to Citizens' Interrogatory 184(b), Gulf provided the following information in table form showing the amounts included in its MFR Schedule C-35 associated with the 159 additional employee positions as well as the amounts included in the adjusted test year Operation & Maintenance Expenses:

Costs for New Employees	Total Amount	NOI Adjs./ Clauses/Capital	Net Amount In Test Year
Base Payroll	$ 7,765,817	$ (3,378,031)	$ 4,387,786
Variable Pay (Incentive Comp.)	702,387	(168,888)	533,499
Medical and Other Group Insurance	956,289		956,289
Employee Savings Plan	242,687		242,687
	$ 9,667,180	$ (3,546,919)	$ 6,120,261

As shown in the above table, Gulf's request to recover costs associated with 159 additional employees results in a $6,120,261 increase in Operation and Maintenance expense in its filing.

Q. **WHAT ASSUMPTIONS HAS GULF MADE REGARDING THE AMOUNT OF VACANCIES DURING THE 2012 TEST YEAR?**

A. Gulf has assumed that it will have zero employee vacancies during the entire 2012 test year in this case. In other words, Gulf has projected as part of its filing that 100% of its budgeted employee positions will be filled by the start of the 2012 test year and that level will be maintained throughout the test year.

Q. **IS THIS A REASONABLE ASSUMPTION?**

A. Absolutely not. Employee vacancies are common for all utilities, including Gulf. It is not the norm for a company to experience a 0% vacancy rate and to have filled its full budgeted employee complement for any given month, let alone an entire year. In fact, Gulf's vacancy rate has been very high since the time of its last rate case, which covers the past nine years. Schedule C-3, page 2 of 2 presents the average actual employee count as well as Gulf's budgeted employee count for each year, 2002 through 2010, and for the six month period ended June 30, 2011. The schedule also presents the percentage variance or vacancy factor for each of these years. As shown on the schedule, Gulf's employee complement has consistently been below the level budgeted by Gulf. For the nine-year period 2002 through 2010, the average vacancy factor was 5.08%. Over the last five years, 2006 through 2010, the average vacancy factor was 6.10%. Using just the six month period ended June 30, 2011, Gulf's average employee complement was 9.81% below the budgeted level.

Q. HOW DOES GULF'S PROJECTED INCREASE IN THE EMPLOYEE COMPLEMENT COMPARE TO THE ACTUAL CHANGES IN EMPLOYEE COMPLEMENT EXPERIENCED BY GULF OVER THE PERIOD SINCE THE LAST RATE CASE?

A. As shown on Schedule C-3, page 2 of 2, the average employee count at Gulf has fluctuated over the period 2002 through 2010, ranging from a 12 employee increase in 2009 to a 9 employee reduction in 2006. The highest annual increase in the average employee complement during the period was 12 employees in 2006. In this case, Gulf has projected that its employee complement will increase by 159 employees from 1,330 as of December 31, 2010 to 1,489 employees before the start of the test year in this case. This increase results from a combination of assuming that 100% of the positions will be filled with zero vacancies as well as a request to add many additional employee positions.

Q. **OF THE 159 ADDITIONAL POSITIONS, HOW MANY ARE THE RESULT OF INCREASING THE BUDGETED NUMBER OF POSITIONS?**

A. During 2010, Gulf's budgeted employee complement was 1,442 employees. The test year budgeted employee complement is 1,489 employees representing a 47 position increase in the budget level. Thus, the 159 employee increase projected by Gulf is the result of both adding new positions and of filling 100% of its budgeted positions for the entire test year. The proposed new positions are addressed in the testimony of several Gulf witnesses in this case.

Q. **HAS GULF ACTUALLY STARTED FILLING POSITIONS SINCE DECEMBER 31, 2010?**

A. Yes. The employee count has increased by 33 employees to 1,365 as of June 30, 2011. While the employee level has increased, it was still 124 employees below the budgeted level as of June 30, 2011.

Q. **FOR THE FIRST SIX MONTHS OF 2011, HOW HAVE THE ACTUAL REGULAR AND OVERTIME PAYROLL COSTS COMPARED TO THE BUDGETED AMOUNTS?**

A. Gulf's response to Citizens' Interrogatory 1 shows that the actual regular and overtime payroll costs for the period January 2011 through June 2011 were $49,763,086, and the actual costs for that same six month period were $45,696,630. Therefore, for the first six months of 2011, the actual regular and overtime payroll costs incurred by Gulf was $4,066,465 below the budgeted amount.

Q. SHOULD GULF'S PROPOSED TEST YEAR LABOR COSTS BE REDUCED IN THIS CASE?

A. Yes. As mentioned previously, it is unrealistic and unreasonable to assume that Gulf will fill 100% of its budgeted employee positions by the start of the January 1, 2012 start of the test year or that Gulf will maintain a 0% vacancy factor throughout the entire 2012 test year. Given the large projected increase in employee positions contained in Gulf's filing compared to historic employee levels, the assumption of 0% vacancy is even more unlikely to occur. In order to reach the level of labor costs incorporated in its filing, Gulf would need to hire 124 additional employees between July1, 2011 and January 1, 2012 and retain all 124 new employees along with 100% of its June 30, 2011 employee complement throughout the 2012 test year. This is highly unlikely, if not impossible, scenario.

Q. WHAT LEVEL OF EMPLOYEES DO YOU RECOMMEND BE REFLECTED IN THE 2012 TEST YEAR?

A. I recommend that Gulf's proposed 159 employee increase from the actual December 31, 2010 level be reduced by 91 positions thereby allowing 68 additional positions, or 42.8% (68 recommended / 159 proposed additions) of the proposed employee increase level. This would allow for the inclusion in the projected test year costs of 1,398 employees, which is 5% higher than the December 31, 2010 employee level. This also results in the allowance of 33 additional employees beyond the actual June 30, 2011 employee complement for a net increase of 68 positions during 2011. This takes into consideration the various new employee positions discussed by Gulf in its testimonies, but also considers the vacancy factor that has been experienced by Gulf.

Q. **HOW DID YOU DETERMINE THE RECOMMENDED TEST YEAR EMPLOYEE LEVEL?**

A. As shown on Schedule C-3, page 2 of 2, I applied the average vacancy factor actually experienced by Gulf during the five-year period 2006 through 2010 of 6.10% to Gulf's budgeted 2012 test year employee complement of 1,489, resulting in a recommended test year employee complement of 1,398 employees. This is 68 employees above the actual December 31, 2010 employee level, 33 of which have already been filled by June 30, 2011.

Q. **WHAT REDUCTION NEEDS TO BE MADE TO GULF'S ADJUSTED TEST YEAR OPERATION AND MAINTENANCE EXPENSES TO IMPLEMENT YOUR RECOMMENDED REDUCTION IN THE PROPOSED TEST YEAR EMPLOYEE COMPLEMENT?**

A. As shown on Schedule C-3, page 1 of 2, Gulf's adjusted 2012 test year expenses should be reduced by $3,195,627. This removes the base payroll, medical and other group insurance costs, and employee savings plan costs included by Gulf in its adjusted test year operation and maintenance expense for the positions I recommend be removed. I have not removed the incentive compensation costs included by Gulf in the test year as part of this adjustment because those costs are being removed elsewhere in my schedules.

<u>Incentive Compensation Program Costs</u>

Q. **WHAT AMOUNT HAS GULF INCLUDED IN ITS 2012 PROJECTED TEST YEAR FOR INCENTIVE COMPENSATION PROGRAM COSTS?**

A. Total projected 2012 costs included $16,464,470 associated with five separate incentive compensation programs. The table below provides a breakdown of the $16,464,470 by each of the five separate programs:

Incentive Compensation Programs	2012 Amounts
Performance Pay Program	$ 13,632,643
Stock Option Expense	724,990
Performance Share Program	1,097,321
Performance Dividend Program	1,007,516
Cash/Spot Awards	2,000
	16,464,470

Of the total costs, $594,954 was removed by the Company as part of its net operating income adjustments and exclusions, resulting in $15,869,516 being incorporated in the adjusted 2012 test year. The table below presents a breakdown of the total cost of $16,464,470 and the adjusted $15,869,516 between operating and maintenance expenses, capital, clearing accounts, and below the line ("BTL") costs.

Incentive Program Costs in Test Year:	Total Amount	NOI Adjs./ Exclusions	Net Amount In Test Year
Operation & Maintenance Expenses	$ 12,893,352	$ (497,410)	$ 12,395,942
Capital	2,978,595		2,978,595
Clearing	494,979		494,979
BTL	97,544	(97,544)	-
Total	$ 16,464,470	$ (594,954)	$ 15,869,516

As shown above, of the total projected incentive compensation plan costs, $12,395,942 remains in operation and maintenance expenses in the filing. Additionally, the clearing costs of $494,979 are allocated between operating and maintenance expenses and capital in the test year.

Q. WHAT IS THE TOTAL AMOUNT OF INCENTIVE COMPENSATION PLAN COSTS REMAINING IN THE ADJUSTED TEST YEAR OPERATION AND MAINTENANCE EXPENSES AND THE ADUSTED TEST YEAR CAPITAL OR PLANT IN SERVICE BALANCES?

A. On Schedule C-4, page 2 of 2, I provide a calculation showing the total amount of incentive program cost charged to O&M expense, as well as the total incentive program costs that were charged to capital in the 2012 test period. The result is that $12,623,632 is included in the adjusted test year O&M expenses and $3,245,884 is in the 2012 capital costs.

Q. WOULD YOU PLEASE DISCUSS THE FOUR SEPARATE INCENTIVE COMPENSATION PLANS THAT MAKE UP THE VAST MAJORITY OF THE 2012 PROJECTED INCENTIVE COMPENSATION PLAN COSTS?

A. Yes. In this testimony I am not addressing the cash/spot awards as the amount is minimal resulting in only $2,000 of costs. Thus, in this testimony I will address the four remaining plans.

Q. WOULD YOU PLEASE FIRST ADDRESS THE STOCK OPTION PROGRAM?

A. Yes. In response to Citizens' Interrogatory 6, Gulf provides the following description of the Stock Option Program:

> **Stock Option Program**
> Stock options reward price increases in Southern Company common stock over the market price on date of grant, over a 10-year term. A long-term performance target percentage of base pay is established for each eligible employee based on his/her grade level. This target percentage may be allocated between stock options and performance shares. The number of stock options granted is dependent on this long-term performance target percentage and allocation, and on the fair value of a stock option on the date of grant.

The incentive compensation program costs budgeted by the Company for 2012 for the Stock Option Program is $724,990. A portion of those costs remain in the adjusted test year expenses and capital in this case.

Q. SHOULD THE COSTS ASSOCIATED WITH THE STOCK OPTION PROGRAM BE PASSED ON TO THE COMPANY'S RATEPAYERS?

A. No, they should not. Clearly, the entire focus of this program is on Southern Company's common stock price. It is a long-term incentive program which encourages certain senior level employees of Southern Company and its subsidiaries, including Gulf, to strive to increase the stock price of Southern Company on behalf of the Company's investors. Clearly, the full focus of this program is on shareholders and not customers. According to the response to Citizens' Request to Produce Documents, Question 14, only exempt employees of Southern Company and its subsidiaries in salary grades of seven and above are eligible for this plan. Non-exempt employees, exempt employees in salary grades below seven and bargaining unit employees are not permitted to participate in this stock option program. Because these benefits provide direct benefits to Southern Company shareholders and not Gulf's ratepayers, I recommend the full costs associated with this program be disallowed and not be passed on to customers.

Q. WOULD YOU PLEASE NOW DISCUSS THE PERFORMANCE SHARE PROGRAM?

A. Gulf's 2012 forecast includes Performance Share Program costs of $1,097,321. In response to Citizens' Interrogatory 6, Gulf provided the following description of the Performance Share Program:

> **Performance Share Program**
> The Performance Shares reward achievement of total shareholder return goals. Employees may receive shares of Southern Company stock dependent on three-year total shareholder return versus industry peers. A target percentage of base pay is established for each eligible employee based on his/her grade level for target level performance. This target percentage may be allocated between stock options and performance shares. The original number of performance shares granted is dependent on the date of the grant. This program was new beginning in 2010. The first possible payout occurs in March, 2013.

Eligibility for this program is the same as the eligibility requirements associated with the Stock Option Program.

Q. SHOULD THE COSTS ASSOCIATED WITH THE PERFORMANCE SHARE PROGRAM BE PASSED ONTO GULF'S CUSTOMERS?

A. No, they should not, for the same reasons as discussed above regarding the Stock Option Program. Clearly, the total goal associated with the program is focused on shareholder returns. The payout calculation is based on a three-year total shareholder return for Southern Company as compared to its industry peers. Clearly, the complete focus of this program is on benefiting shareholders and not ratepayers. Thus, I recommend these costs be disallowed.

Q. WHAT IS THE PERFORMANCE DIVIDEND PROGRAM?

A. The Performance Dividend Program is being phased out and is being replaced with the Performance Share Program previously discussed. Gulf's response to Citizens' Interrogatory 6 provides the following description of the Performance Dividend Program:

> **Performance Dividend Program**
> Performance dividends reward the achievement of total shareholder return goals. Employees may receive case compensation dependent on the number of stock options held at year-end, Southern Company's dividends paid during the year and four-year total shareholder return versus industry

> peers. Employees with outstanding stock options – granted prior to 2010 – are eligible. This program is being phased out with the last possible payment in March 2013.

Clearly, the focus on this program is again on shareholder returns as it is based entirely on Southern Company's dividend paid during the year and the four-year total shareholder return goals as compared to industry peers. The eligibility requirements are consistent with the requirements for the Stock Option Plan and the Performance Share Program.

Q. CONSISTENT WITH YOUR RECOMMENDATION REGARDING THE STOCK OPTION PLAN AND THE PERFORMANCE SHARE PROGRAM, SHOULD THE COSTS INCLUDED IN THE TEST YEAR FOR THE PERFORMANCE DIVIDEND PROGRAM ALSO BE DISALLOWED?

A. Yes, I recommend that the full projected costs of $1,007,516 be disallowed. This program does not benefit ratepayers; thus, these costs should not be passed on to ratepayers. The costs should be funded by the Southern Company's shareholders who are the beneficiaries and prime focus of the goals within the plans.

Q. WOULD YOU PLEASE DISCUSS THE PERFORMANCE PAY PROGRAM?

A. The bulk of the projected incentive compensation plan cost fell within this category, representing approximately $13.6 million of the $16.5 million total incentive compensation program projections. The Performance Pay Program ("PPP") is Gulf's annual incentive compensation plan. It is short-term in nature. The performance measures that are used to determine the performance of the employees under the PPP are the same for all Gulf employees; however, the level of compensation that falls under the program varies among the employees.

Q. WHICH EMPLOYEES ARE ELIGIBLE FOR THE PPP PROGRAM AND WHAT ARE THE PAYOUT TARGETS BY EMPLOYEE TYPE?

A. All regular full-time employees and most part-time employees, with a few exceptions, are eligible to participate in the PPP. The Target Award as a percentage of an employee's base salary varies depending on the employee category. For Gulf Power International Brotherhood of Electric Workers ("IBEW") bargaining unit employees, the Target Award is 5% of base pay. For the remaining non-exempt employees, the Target Award is 10% of base salary. This 10% level is also applicable to the exempt employees who fall within salary grades 1 through 5. For salary grade 6 employees, the Target Award increases to 12.5% of base salary. For employees falling within grade levels 7 through 15, the Target Award percentage ranges from 25% to 60%, depending on the grade. For each participant the Target Award is determined as a percentage of that employee's base pay.

Q. WHAT ARE THE PERFORMANCE GOALS THAT ARE USED TO EVALUATE THE PAYOUT LEVELS FOR THE PPP?

A. One-third of the plan weighting is based on Gulf's achieved return on equity, one-third of the payout weighting is based on Southern Company's earnings per share, and the remaining one-third is based on the Business Units' operational goals. Gulf Power's operation goals would be specific to Gulf Power. However, prior to any Performance Pay Program awards being made, Southern Company's earnings per share must exceed the prior year's dividends; otherwise, there will be no PPP opportunity. As a result, the key trigger or the key focus of the plan is Southern Company's earnings per share.

Q. WHAT IS THE SOUTHERN COMPANY'S EARNINGS PER SHARE GOALS UNDER THE PPP?

A. The table below presents the targeted Southern earnings per share under the plan and the actual Southern earnings per share for each year 2007 through 2010, as well as the target under the 2011 PPP.

	2007	2008	2009	2010	2011
Target	$ 2.16	$ 2.32	$ 2.38	$ 2.33	$ 2.52
Result	$ 2.21	$ 2.37	$ 2.32	$ 2.37	N/A

Q. PLEASE COMPARE THE HISTORIC RETURN ON EQUITY GOALS UNDER THE PPP WITH THE RESULTS THAT WERE ACTUALLY ACHIEVED.

A. The table below provides for each year, 2007 through 2011, the PPP target for Gulf's return on equity as well as the actual achieved Gulf return on equity for each year 2007 through 2010. The 2007 through 2010 amounts were provided by Gulf in response to Citizens' Interrogatory 191, and the 2011 target was provided in the Company's response to Citizen's Interrogatory 4.

	2007	2008	2009	2010	2011
Target	13.50%	13.25%	12.70%	11.90%	12.00%
Result	13.25%	12.66%	12.18%	11.69%	N/A

As seen from these results, Gulf fared well on its return on equity results, as measured under its PPP plan. Even during the last few years of economic turmoil, Gulf showed returns of 12.18% in 2009 and 11.69% in 2010.

Q. IS THERE A PROBLEM WITH THE WAY THE COMPANY'S PERFORMANCE PAY PROGRAM IS STRUCTURED AND DESIGNED?

A. Yes. The primary drivers and key focus of the program are financial goals that benefit Southern Company's shareholders but not Gulf's ratepayers in the state of Florida. As previously mentioned, in order for a payout to even occur under the plan, Southern Company's earnings per share must exceed the prior year's dividends. This places the participants' primary emphasis on increasing Southern Company's earnings. The large amount of emphasis and weighting on Gulf's return on equity as well as Southern Company's earnings per share shifts the focus of the plan to areas that benefit shareholders and could be detrimental to the level of service provided to customers.

The large emphasis on return on equity and earnings could shift focus away from operations in order to help the Company achieve its earnings targets. While one-third of the plan targets Gulf Powers operational goals, which could benefit the ratepayers, the operational goals are far outweighed by Southern Company's financial goals.

Q. SHOULD THE PPP COSTS BE RECOVERED FROM GULF'S RATEPAYERS IN THE STATE OF FLORIDA?

A. No, they should not. I recommend that the PPP program costs be disallowed in its entirety. Many of the ratepayers in the state of Florida, particularly along the Gulf coast which was impacted by both the significant economic downturn and the oil spill, remain in precarious financial positions. It is not reasonable to expect ratepayers to fund incentive plans that almost entirely benefit the shareholders of Southern Company.

Q. HAS THE COMMISSION PREVIOUSLY DISALLOWED THE RECOVERY OF INCENTIVE COMPENSATION FROM RATEPAYERS?

A. Yes. In Order No. PSC-10-0131-FOF-EI issued on March 5, 2010, at page 115, the Commission disallowed recovery from ratepayers of Progress Energy Florida's incentive compensation plan costs. Specifically, the Order found as follows:

> We believe that incentive compensation provides no benefit to the ratepayers and constitutes nothing more than added compensation to employees. Especially in light of today's economic climate, we believe that PEF should pay the entire cost of incentive compensation, as its customers do not receive a significant benefit from it. Accordingly, we find that the 2010 allowance for incentive compensation shall be reduced by $32,854,378 jurisdictional ($37,465,650 system).

Additionally, in Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, the Commission disallowed part of Tampa Electric Company's incentive compensation expense, specifically stating that ". . . the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy." As a result, the Commission disallowed the portion of the incentive compensation that was tied to the parent company's results. Additionally, while the economic conditions in the State of Florida may have stabilized somewhat since the Commission disallowed Progress Energy Florida's incentive compensation plan costs, economic conditions within Gulf Power's service area since the end of the "Great Recession" have not significantly improved, due in large part to the continued impact of the BP Gulf Oil Spill.

Q. IN DETERMINING THE BUDGETED 2012 PPP COSTS INCORPORATED IN THE COMPANY'S FILING, DID THE COMPANY ASSUME THAT THE PAYOUTS WOULD BE AT THE PPP TARGET LEVEL?

A. No. The Company's response to Citizens' Interrogatory 184, at page 4, shows that the Company has assumed a total result of 125% of target levels. The 125% was calculated assuming that: 1) the Southern Company earnings per share goal, which is given one-third weighting, would be at target; 2) the Gulf return on equity goal with a one-third weighting would be at 125% of target; and 3) the operational goals would be at 150% of target. Thus, the Company is attempting to incorporate into base rates an assumption that Gulf will exceed its PPP goals and that it will achieve a return on equity for Gulf that is at 125% payout level, or above the target goal. Additionally, if the Company is assuming that it can greatly exceed the operational goals (achieve 150% of target), then clearly those goals are not set at a level that would cause the employees to stretch to achieve the goals. If the Company is already assuming that its employees will greatly exceed the goals, one has to question whether or not the 2012 operation goals are truly incenting exceptional employee performance.

Q. WHAT IS YOUR OVERALL RECOMMENDATION WITH REGARDS TO THE TOTAL INCENTIVE COMPENSATION COSTS INCLUDED IN THE 2012 TEST YEAR?

A. I recommend that 100% of these costs be disallowed and be funded by shareholders for the reasons discussed above. None of these costs, with possibly the exception of the $2,000 included for the spot/cash awards, should be passed onto the Company's captive ratepayers. As shown on Schedule C-4, page 1 of 2, Gulf's adjusted test year expenses should be reduced by $12,623,632 to remove the incentive compensation costs and plant in service should be reduced by $1,217,206. Similarly, depreciation expense and accumulated depreciation should be reduced by $42,967.

Q. WHY ARE YOU ALSO REDUCING RATE BASE AS A RESULT OF YOUR RECOMMENDATION TO REMOVE THE INCENTIVE COMPENSATION COSTS FROM THE TEST YEAR?

A. A portion of the incentive compensation costs is projected to be capitalized by the Company during the test year. The purpose of my reduction to rate base is to remove the estimated incentive plan costs that are capitalized as part of plant in service in the Company's filing. In response to Citizen's Interrogatory 184, at pages 15 and 16, Gulf indicated that a portion of its capitalized incentive plan costs will affect the 13-month average rate base and the resulting revenue requirement; however, the extent to which rate base is impacted is also influenced by the portion of the costs that would go to clause related projects and that which would go to CWIP. In the response the Company indicated that it is difficult to quantify the precise amount of test year capitalized labor costs that is included in the 13-month average plant in service balance. It did not provide an estimate. Since the Company failed to provide such an estimate, I have assumed that 75% of the capitalized costs would be booked to plant in service in the Company's filing. In making my adjustment, after applying the 75% factor I then applied a 50% factor as the test year is based on a 13-month average rate base balance. The result is my recommended reduction to plant in service to remove the impact of incentive compensation costs of $1,217,206. If these costs are not removed from rate base, then the Company would earn a return on and of those costs for many years into the future.

Q. **DO THE PROJECTED TEST YEAR CHARGES TO GULF FROM SOUTHERN COMPANY SERVICES INCLUDE AMOUNTS ASSOCIATED WITH THE INCENTIVE COMPENSATION PROGRAMS THAT YOU RECOMMEND BE REMOVED IN THIS CASE?**

A. At this time I do not know if the charges from SCS include costs associated with Southern Company Services employees' participation in the PPP or other incentive programs. If any of the charges from SCS or other affiliates that are incorporated in Gulf's adjusted

2012 test year expenses include costs associated with the PPP, the various stock option plans or other incentive compensation plans, those costs should also be removed and not passed on to Gulf's ratepayers.

Q. **SHOULD PAYROLL TAX EXPENSE ALSO BE ADJUSTED TO REMOVE THE IMPACT OF THE INCENTIVE COMPENSATION COSTS ON PAYROLL TAX EXPENSE?**

A. Yes. I Schedule C-5 I have estimated the impact on test year payroll tax expense resulting from my recommended removal of the incentive compensation plan costs, reducing Gulf's adjusted test year payroll tax expense by $799,606.

<u>Other Employee Benefits</u>

Q. **MFR SCHEDULE C-35 SHOWS "OTHER EMPLOYEE BENEFITS" COSTS INCREASING FROM $610,136 IN 2010 TO PROJECTED COSTS OF $815,104 IN THE 2012 TEST YEAR, RESULTING IN AN INCREASE OF 33.59%. HAVE YOU REVIEWED THE COSTS INCLUDED IN THE 2012 TEST YEAR FOR "OTHER EMPLOYEE BENEFITS"?**

A. Citizens' Interrogatory 184 asked the Company to provide a breakdown of the projected 2012 test year Other Employee Benefits costs of $815,104 and to explain the increase above the test year level. As part of its response, Gulf provided a breakdown of the items included in the 2012 expense. Based on a review of the response, I recommend that the costs associated with the following Other Employee Benefits be removed: 1) Interest on Deferred Compensation of $362,309; 2) Executive Financial Planning of $61,452; and, 3) SCS Early Retirement of $50,340.

Q. AT PAGE 12 OF HIS TESTIMONY, GULF WITNESS MCMILLAN INDICATES THAT THE EXPENSE RELATED TO MANAGEMENT FINANCIAL PLANNING SERVICES HAVE BEEN REMOVED "CONSISTENT WITH THE COMMISSION'S DECISION IN GULF'S LAST RATE CASE." DID GULF REMOVE ALL OF THE FINANCIAL PLANNING SERVICES COSTS CONSISTENT WITH THE COMMISSION'S PRIOR DECISION?

A. No, it did not. On McMillan's Exhibit__(RJM-1), Schedule 4, page 3, he removes $13,000 from test year expenses for "Management Financial Planning." However, based on the response to Citizens' Interrogatory 184(c), test year expenses include $61,452 for amounts paid to financial planning vendors for the executive financial planning services. All of these costs should be removed. On Schedule C-1, page 2, I have removed the $48,000 of executive financial planning costs remaining in the 2012 test year. Gulf's executives receive adequate compensation to provide for their own financial planning consultants, and ratepayers should not be required to fund any of these costs in rates.

Q. WOULD YOU PLEASE DISCUSS THE REMAINING OTHER EMPLOYEE BENEFIT COSTS THAT YOU RECOMMEND BE REMOVED?

A. Yes. The response to Citizens' Interrogatory 184(c) shows the "Interest on Deferred Compensation" of $362,309 as the result of applying a 6.78% interest rate on projected 2012 year end compensation deferral balances of $5,343,788. There is no discussion of why interest is being paid on these deferred compensation balances or how the deferred compensation amounts resulted. Presumably this pertains to compensation that executives or senior level employees of Gulf have elected to defer with a generous interest rate being applied. These interest costs, which are being applied at an estimated 2012 prime rate of 6.78%, have not been justified and should not be passed on to Gulf's ratepayers. There was also no discussion of why such a high interest rate (6.78%) is being applied or why such a high interest rate is justified.

The same response shows $50,340 being included for "SCS Early Retirement." It is described as follows: "Monthly 2010 actual accrual amount was $4,195. Assumed no change and budgeted $50,340 for 2012." There is no further discussion regarding what the "SCS Early Retirement" accrual was for or why it should be passed on to Gulf's ratepayers. I recommend this amount be removed.

Each of these items is removed on my Schedule C-1, page 2.

Rate Case Expense

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO RATE CASE EXPENSE.

A. As discussed in the Direct Testimony of Company witness Constance J. Erickson, Gulf has estimated rate case expenses totaling $2,800,000, which it proposes to amortize over a four-year period beginning in 2012. As shown on MFR Schedule C-10 from the Company's filing, this adjustment increases Gulf's projected 2012 test year O&M expense by $700,000. In addition, as shown on MFR Schedule B-17, page 1, line 25, Gulf proposes to include the 13-month average unamortized balance of rate case expense in the working capital component of rate base.

Q. DO YOU AGREE THE COMPANY'S RATE CASE EXPENSE ADJUSTMENT IS REASONABLE?

A. Not entirely. There are several amounts included in the Company's projected rate case expense that are questionable, including the Company's estimate for Meals and Travel expenses which total $175,000, as well as many of the items included in Other Expenses which total $425,000. As I explain below, I believe that the Company's estimates for these two items are excessive and/or unsupported.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN GULF'S ESTIMATE FOR MEALS AND TRAVEL EXPENSES?

A. Citizens' Interrogatory 172 requested that Gulf provide a breakout of the $175,000 included in rate case expense for Meals and Travel costs. In response, the Company provided the data shown in the following table:

Estimated Meals and Travel Expenses

Category	Amount
Hotels	$ 90,000
Transportation	$ 24,500
Food	$ 44,000
Miscellaneous	$ 16,500
	$ 175,000

Source: OPC-4-172

The Company provided a further breakout of the costs listed in the table above in the workpapers provided in Citizens' First Request to Produce Documents Nos. 4 and 5 for MFR Schedule C-10[1]. One such workpaper, titled Estimate of Rate Case Travel Expenses ("Estimate"), broke out the estimated meals and travel expenses between the following categories: Hearing, PreHearing, Depositions, Mock Hearings and

[1] This response was referred to in the response to Citizens' Second Request to Produce Documents No. 77, which requested documentation which supports the Company's estimated rate case expense of $2.8 million.

Meetings/OT. It should be noted that the estimates listed on this workpaper totaled $187,951, or $12,951 higher than the $175,000 reflected in the Company's rate case request for meals and travel expenses. As shown in the table below, when compared to the amounts provided in response to Citizens' Interrogatory 172 (which are the amounts reflected in Gulf's filing), the majority of this variance falls under the Miscellaneous category.

Category	Per Gulf Workpaper	Per OPC-4-172	Difference
Hotels	$ 90,066	$ 90,000	$ 66
Transportation	$ 22,968	$ 24,500	$ (1,532)
Food	$ 45,985	$ 44,000	$ 1,985
Miscellaneous	$ 28,932	$ 16,500	$ 12,432
	$ 187,951	$ 175,000	$ 12,951

Q. WHICH CATEGORIES OF GULF'S ESTIMATED MEALS AND TRAVEL EXPENSES DO YOU BELIEVE ARE EXCESSIVE?

A. The categories of Gulf's estimated meals and travel expenses that I believe are excessive are the Company's estimates for hotel rooms, food and transportation. Specifically, the Company has estimated that 60 people will travel to and attend 10 days of hearings in this proceeding. As shown in the table below, which reflects the estimates shown on the Estimate workpaper, this translates to estimated lodging expenses of $85,980 and estimated food expense totaling $39,000 over a ten-day period.

Hearing	No. of Days	Cost/Day /Fillup		# of People /Vehicles	Total	
Hotel Rooms	10	$	141	54	$	76,140
Suites	10	$	164	6	$	9,840
Total Lodging					$	85,980
Breakfast	10	$	15	60	$	9,000
Lunch	10	$	15	60	$	9,000
Dinner	10	$	35	60	$	21,000
					$	39,000

Q. WHY DO YOU BELIEVE THESE AMOUNTS ARE EXCESSIVE?

A. The amounts are excessive as they include an unreasonable number of people attending hearings as well as an incorrect assumption regarding the number of hearing days. Since there are 17 Gulf witnesses sponsoring testimony in this proceeding, for the Company to include 60 people as attending hearings on its behalf is excessive. This is especially true when one considers that the Company's estimates reflect that all 60 people will each be attending ten days of the hearings. The likelihood that 60 people will each attend all hearing days seems questionable and unreasonable. Therefore, the Company's estimate for hotels, meals and travel expenses should be adjusted.

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT.

A. My recommend adjustment is presented on Schedule C-6. As shown on page 2 of Schedule C-6, I began with Gulf's workpaper calculating its estimated hotel, travel and meal costs. I provide a side by side comparison of the various amounts per Gulf's workpapers and per my recommendation. In the per OPC column, I broke out the public hearings from the technical hearings. It is my understanding that both public hearings in this case occurred on the same day and that approximately six people attended the public hearings on Gulf's behalf. As shown on Schedule C-6, page 2, lines 32 – 37, I have assumed that six people would require one night of lodging and meals associated with the public hearings, and that three vehicles would be rented.

The Commission has set aside five days for the technical hearings in this case. Thus, I have reduced the hearing days contained in Gulf's workpaper from 10 days to 5 days. In order to address the excessive number of people Gulf projected as attending every day of hearings on its behalf (i.e., 60 people), I recommend that the Company's estimate be adjusted to reflect one member of support personnel for each of the Company's 17 witnesses in this proceeding, or 34 people. This adjustment reduces the number of people attending the hearings from 60 to 34, which appears to be a more reasonable estimate. Even the 34 people may be over-estimated. While certain people, such as legal counsel, some senior management personnel and a few witness would likely be needed to attend all five hearing days, it is unlikely that every witness will need to attend all five days of technical hearings in this case. I also reduce the amount of needed rental vans and cars to correspond to the reduction in the number of people attending the hearings on Gulf's behalf. This adjustment reduces the estimated meals and travel expenses by $102,273 as shown on Schedule C-6, page 2, line 39. This reduction flows through to page 1 of Schedule C-6, line A.4.

Q. **YOU STATED THAT SEVERAL ITEMS INCLUDED IN GULF'S ESTIMATE FOR OTHER EXPENSES ARE ALSO QUESTIONABLE. PLEASE ELABORATE.**

A. In the Other Expenses category of Gulf's projected rate case expense, the Company included estimated expenses from Southern Company Services ("SCS") which totaled

$321,000[2] as well as $59,000 of overtime labor. I have removed these amounts from the Company's projected test year rate case expense.

Q. WHY HAVE YOU REMOVED THESE ITEMS FROM RATE CASE EXPENSE?

A. I am removing the estimated rate case costs projected to be charged to Gulf from SCS for several reasons. First, the Information Technology, Human Resources and Accounting functions are already performed in-house at Gulf and there has been no showing that additional support from SCS specific to the rate case in these areas are needed. Gulf has included $99,000 in its projected rate cases costs for these types of charges from SCS. The projected charges from SCS also include $222,000 for Cost of Service Study assistance. This is in addition to amounts from outside consultants for assistance in the rate case. There has also been no showing that the costs shown as coming from SCS are incremental to costs already projected to be allocated or charged to Gulf from SCS during the test year. I recommended that the full $321,000 of charges from SCS that are included in the projected rate case expense be removed.

As it relates to removing the estimated overtime labor costs, Gulf's internal labor costs should already be provided for in Gulf's 2012 budget and are thus already incorporated in the filing. Thus, to include these overtime labor costs in rate case expense constitutes a double count, so it has been removed.

Q. WHAT IS YOUR OVERALL ADJUSTMENT TO GULF'S PROJECTED TEST YEAR RATE CASE EXPENSE?

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[2] The response to Citizens' Interrogatory 172 breaks out this amount as follows: Cost of Service Study - $222,000; IT/Computers - $20,000; and Other Areas (HR, Accounting, etc.) - $79,000.

A. As shown on Schedule C-6, my recommended adjustments, which total $482,273, decreases Gulf's projected rate case costs to $2,317,727. The annual amortization of these costs, using Gulf's proposed four-year amortization period, is $579,432, which is $120,568 less than the amount proposed by Gulf. Thus, test year amortization expense should be reduced by $120,568.

Unamortized Rate Case Expense

Q. HAS THE COMPANY INCLUDED THE PROJECTED 2012 BALANCE OF UNAMORTIZED RATE CASE EXPENSE IN ITS WORKING CAPITAL REQUEST IN THIS CASE?

A. Yes. The working capital component of rate base for the 2012 test year includes $2,450,000 for Gulf's projected unamortized rate case expense associated with this case.

Q. SHOULD GULF BE PERMITTED TO INCREASE RATE BASE FOR THE UNAMORTIZED RATE CASE EXPENSE BALANCE?

A. No, it should not. The Commission has consistently disallowed the inclusion of unamortized rate case expense in working capital. This long standing Commission policy was recently reaffirmed in Commission Order No. PSC-10-0131-FOF-EI involving Progress Energy Florida. At pages 71 to 72 of the order in that case, the Commission stated as follows with regard to unamortized rate case expense:

> We have a long-standing policy in electric and gas rate cases of excluding unamortized rate expense from working capital, as demonstrated in a number of prior cases. The rationale for this position was that ratepayers and shareholders should share the cost of a rate case: i.e., the cost of the rate case would be included in the O&M expenses, but the unamortized portion would be removed from working capital. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.

> While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period (Section 367.0816,F.S.). While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.
>
> We agree with the long-standing policy that the cost of the rate case should be shared, and therefore find that the unamortized rate case expense amount of $2,787,000 shall be removed from working capital.

In a footnote on page 71 of the order, the Commission identified the following cases which demonstrate its long-standing policy in electric and gas cases of excluding the unamortized rate case expense from working capital:

> Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Application of Gulf Power Company for a rate increase; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009; in Docket No. 08317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. PSC-09-0375-PAA-GU, In re: Petition for rate increase by Florida Public Utilities Company.

Q. DO YOU RECOMMEND THAT THE UNAMORTIZED RATE CASE EXPENSE BE EXCLUDED FROM RATE BASE IN THIS CASE?

A. Yes, I recommend that the Commission continue to follow its long-standing policy in electric cases of not allowing inclusion of the unamortized rate case expense in rate base. Consistent with the Commission's finding in the Progress Energy Florida case it would be unfair to customers to pay a return on the costs accrued by the Company in this case that were used by Gulf to increase those rates charged to customers. On Schedule B-1, page 2, I have removed the full amount of the unamortized balance of rate case expense from working capital in this case, reducing rate base by $2,450,000.

Income Tax Expense

Q. HAVE YOU ADJUSTED INCOME TAX EXPENSE TO REFLECT THE IMPACT OF THE ADJUSTMENTS SPONSORED BY CITIZENS' WITNESSES TO NET OPERATING INCOME?

A. Yes. On Schedule C-7, I calculate the impact on income tax expense, including both federal and state, resulting from the recommended adjustments to operating expenses. The result is carried forward to the Net Operating Income Summary on Schedule C-1, page 2.

Interest Synchronization

Q. WHAT IS THE PURPOSE OF YOUR INTEREST SYNCHRONIZATION ADJUSTMENT ON SCHEDULE C-8?

A. The interest synchronization adjustment synchronizes the adjusted rate base and cost of capital with the income tax calculation. On Gulf Exhibit__(RJM-1), Schedule 11, Gulf included an adjustment to synchronize its proposed rate base and cost of debt with the interest expense included in its income tax expense calculation.

Citizens' proposed rate base and weighted cost of debt differ from the Company's proposed amounts. Thus, our recommended interest deduction for determining rate year income tax expense will differ from the interest deduction used by Gulf in its filing. Schedule C-8 shows the calculation of the impact on income tax expense which would be experienced as a result of the interest deduction being lower for tax purposes based on Citizens' proposed rate base and weighted cost of debt.

Parent Debt Adjustment

Q. ARE CITIZENS RECOMMENDING A PARENT DEBT ADJUSTMENT BE MADE IN THIS CASE?

A. Yes. Dr. Woolridge addresses the Company's position that the adjustment should not be made in this case and explains why, in fact, it should be made. I am sponsoring the amount of the adjustment.

Q. ON MFR SCHEDULE C-24, GULF PROVIDES THE CALCULATION OF THE PARENT DEBT ADJUSTMENT. WAS THE AMOUNT OF ADJUSTMENT CALCULATED CORRECTLY BY GULF IN ITS FILING?

A. Based on my review of MFR C-24, page 1 of 2, it appears that the Company has correctly calculated the amount of reduction to income tax expense that will result from the Parent Debt Adjustment. While on that same MFR schedule the Company indicates that a Parent Debt Adjustment is not appropriate, it has none the less presented the information needed to calculate the adjustment. The Company has calculated the adjustment as the weighted cost of Parent Debt times the consolidated tax rate times the equity of the subsidiary, or Gulf Power, excluding retained earnings. This results in the 2012 Parent Debt Adjustment, which is a reduction to income tax expense of $2,126,000. The calculation of the adjustment presented by Gulf is consistent with the Parent Debt Adjustment rule, Rule 25-14.004(4), F.A.C., which states:

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall me multiplied by the statutory tax rate applicable to the consolidated entity. These results shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

Based on a review of the Company's calculation, it appears it has followed the methodology specified within the Commission rule.

Q. WHAT IS THE RESULTING ADJUSTMENT?

A. The result is a $2,126,000 reduction to income tax expense. After application of the jurisdictional separation factor associated with income taxes of .8305076, the result is a $1,766,000 reduction to Florida jurisdictional income tax expense. I have reflected this adjustment on Schedule C-1, page 2 of 2.

<u>DEFFERED TAXES</u>

Q. THE DEFERRED TAX COMPONENT OF THE CAPITAL STRUCTURE INCREASES SIGNIFICANTLY BETWEEN THE 2010 HISTORIC PERIOD AND THE 2012 TEST YEAR. COULD YOU PLEASE DISCUSS THIS INCREASE?

A. Yes. MFR Schedule D-1a shows that the deferred tax component of the jurisdictional capital structure goes from $170,937,000 in the 2010 historic year to $257,098,000 in the 2012 test year. The schedule also shows that the percentage of the jurisdictional capital structure associated with deferred taxes increases from 11.27% in 2010 to 15.34% in 2012. As the deferred taxes are included in the capital structure at zero cost, the increase in the percentage of the capital structure associated with deferred taxes is a benefit to ratepayers as it reduces the overall required rate of return.

Q. WHAT WOULD CAUSE SUCH A LARGE INCREASE IN THE DEFERRED TAX BALANCE IN THE JURSIDICATIONAL CAPITAL STRUCTURE DURING THE TWO YEAR PERIOD?

A. *The Small Business Jobs Act of 2010*, signed into law on September 27, 2010, included provisions extending 50 percent bonus depreciation allowances on qualifying investments in new business equipment and assets placed into service in 2010. Subsequently, *The Reid-McConnell Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010* signed into law on December 17, 2010 extended and temporarily increased this bonus depreciation provision for qualifying investments in new business equipment. For investments placed in service after September 8, 2010 and through December 31, 2011, the bill provides for 100 percent bonus depreciation. For investments placed in service after December 31, 2011 and through December 31, 2012, the bill provides for 50 percent bonus depreciation. The bonus depreciation allowed for under these acts substantially increases the accumulated deferred income tax balances on Gulf's books. Gulf's filing would have included the impacts of the 50% and 100% bonus depreciation.

Q. ARE YOU AWARE OF ANY EVENTS THAT COULD CAUSE THE BONUS DEPRECIATION ALLOWANCE TO INCREASE FURTHER BETWEEN NOW AND THE END OF THE 2012 TEST YEAR IN THIS CASE?

A. Yes. On September 8, 2011, President Obama presented *The American Jobs Act of 2011* to Congress for approval. Under President Obama's proposal, the 100% bonus depreciation provision would be extended through December 31, 2012 thereby increasing the current 50% bonus depreciation rate for 2012 to 100%. At this time, President Obama's proposal has not been acted upon by the U.S. Congress.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT ASSOCIATED WITH THE PROPOSED ACT?

A. Since the current law allows for 50% bonus depreciation in 2012, I am not recommending an adjustment at this time. However, if an act is signed into law increasing the bonus depreciation provisions for 2012 from 50% to 100% prior to the completion of hearings in this case, then I recommend that the impacts be reflected in this case. If the bonus depreciation is increased to 100% for 2012, which may be known by the time the Commission decides Gulf's rate case, then the deferred tax component of the capital structure should be increased to reflect the impacts.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

SUPPLEMENTAL DIRECT TESTIMONY

OF

DONNA RAMAS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 110138-EI

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I previously filed direct testimony on behalf of the Office of Public Counsel ("OPC") in this docket.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. The purpose of my supplemental direct testimony is to address the appropriate amount to be included in rate base and expenses associated with the Crist Unit 6 and 7 turbine upgrade projects. I provide the amount that OPC recommends for inclusion in the revenue requirements and base rates in this proceeding for those projects. I also address the supplemental direct testimony of Gulf Power Company ("Gulf" or "Company") witness Richard J. McMillan on the same issue.

Q. **WOULD YOU PLEASE BRIEFLY DESCRIBE THE TURBINE UPGRADE PROJECTS THAT ARE AT ISSUE IN THIS CASE?**

A. Yes. The turbine upgrades consist of three separate projects. These include:

- Crist Unit 7 High Pressure/Intermediate Pressure upgrades that were completed and placed into service in January 2010 at a cost of $15.3 million;
- Crist Unit 6 High Pressure/Intermediate Pressure upgrades that are currently scheduled to be completed in May 2012 at an estimated cost of $22.2 million;
- Crist Unit 7 lower pressure upgrades that are scheduled to be complete in December 2012 at an estimated cost of $26.8 million.

Each of the turbine upgrade projects at issue in this case were or are being done to upgrade the capacity of the Crist unit 6 and 7 turbines. The projects will result in additional energy output from the units. The response to Staff's Sixteenth Set of Interrogatories, Question 213(a) indicates that the projects improve the heat rate on the units and add 30MW of capacity. These turbine upgrades are not part of the actual scrubber projects, but rather serve to increase the heat rating and capacity of the units.

Exhibit No. __(RJM-3), Schedule 1, attached to the supplemental testimony of Gulf witness McMillan identifies the total projected cost of the three projects as $63,913,000 and the annual depreciation expenses associated with the three turbine upgrade projects as $2,237,000.

Q. **WOULD YOU PLEASE BRIEFLY SUMMARIZE GULF'S SUPPLEMENTAL POSITION WITH REGARDS TO THE CRIST UNIT 6 AND 7 TURBINE UPGRADE PROJECTS?**

A. In its supplemental filing, Gulf is requesting that the Crist Unit 6 and Unit 7 upgrade projects be included in base rates on an annualized basis and treated as though each of the three separate projects were in service for the entire test year. Gulf has projected a total annualized revenue requirement associated with the turbine upgrades, based on its requested rate of return, of $8,104,000. If the traditional 13-month average test year methodology approach were followed, the revenue requirement impact, at Gulf's requested rate of return, would be $3,768,000[1]. In acknowledgement of the fact that two of the three projects will not be in service for portions of the 2012 test year, Gulf has proposed that $3,512,000 be credited to customers during 2012 by adjusting the Environmental Cost Recovery Clause ("ECRC") factor downward effective on the date new base rates from this case goes into effect. The $3,512,000 is the projected amount that would be collected from customers from March 12, 2012 to December 31, 2012 for the difference between what would be in base rates if the revenue requirement was based on the traditional 13-month average test year amounts. The credit would discontinue on January 1, 2013, at which point the costs would be recovered from customers based on an annualized cost level.

As an alternative, Gulf proposes two separate base rate increases. The initial base rate increase would include the turbine upgrades based on their projected 13-month average balances for the 2012 test year. The first step adds $3,768,000 to Gulf's previously proposed increase in rates. The second base rate increase would take effect January 1, 2013 and reflect a full annualized cost for each of the turbine upgrade projects. The second base rate increase would be $4,336,000 bringing the total amount included in base rates for the turbine upgrade projects to $8,104,000.

[11] Exhibit No.__(RJM-3), Schedule 1.

Q. DO YOU AGREE WITH GULF'S PROPOSED APPROACH?

A. No, I do not. While it is appropriate to include the Crist unit 7 high pressure/intermediate pressure upgrades in plant in service in each month of the test year given their January 2010 in-service date, the remaining two turbine upgrade projects should not be recovered from customers on an annualized basis. The Crist unit 6 high pressure/intermediate pressure turbine upgrades are not projected to be complete or serving customers until May 2012, which is five months into the 2012 test year, and the Crist unit 7 low pressure turbine upgrades will not be used and useful in providing service to customers until the final month of the 2012 test year. Essentially, Gulf proposes to deliberately overstate rate base for the projected test year, and compensate for having done so by using the cost recovery clause as a conduit through which to flow back the corresponding overcollection of base rate revenues. Through these means, Gulf would effectively accomplish the result (i.e., rates that increase with annually increasing investment) that it would have realized had the turbine investments remained in the environmental cost recovery clause. However, there are no compelling reasons to distort ratemaking procedures in this manner so as to allow for special treatment for the turbine upgrade projects. Recovery of these projects should follow the traditional ratemaking methodology that is long established in Florida. The turbine upgrade projects should be included in rates based on the average period in which they will be in service during the 2012 test year in this case. To allow otherwise would be the equivalent of single issue ratemaking and would violate the matching principle.

Q. HAS GULF PRESENTED ANY COMPELLING REASONS THAT SHOULD CAUSE THE COMMISSION TO DEVIATE FROM THE LONG STANDING REGULATORY PRACTICES FOR THE TURBINE UPGRADE PROJECTS?

A. No, it has not. Beginning at page 6 of his supplemental testimony, Mr. McMillan contends that the projects will provide fuel and capacity cost savings to customers and that customers will be receiving the savings from the projects through the fuel clause and capacity clause. This does not justify treating the projects any differently than the other plant additions incorporated in the company's case. Upgrading components of generation plants are normal plant additions that should not be given special treatment for ratemaking purposes. If Gulf had not attempted to include these projects in the ECRC, they would have been treated like any other plant additions in the rate case filing using the traditional 13-month average approach.

Q. **WOULD YOU PLEASE DISCUSS THE MATCHING PRINCIPLE AND HOW GULF'S PROPOSED TREATMENT OF THE TURBINE UPGRADE PROJECTS BEING PLACED INTO SERVICE IN 2012 VIOLATES THAT PRINCIPLE.**

A. Yes. It is not appropriate to annualize single items of the revenue requirement equation, such as the two turbine upgrades that Gulf plans to place into service in May and December of the 2012 test year, and have rates result that will be reflective of conditions in a rate effective period. Over time, many changes in a Company's cost structure occur. In addition to rate base increasing as new plant is added, existing plant will continue to be depreciated and some plant will be retired. Revenue will increase as customers are added to the system and expenses will fluctuate. Changes to individual components of the overall cost structure do not occur in a vacuum or in isolation. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs.

In fact, one can view Gulf's supplemental filing as resulting in two completely different test periods with a separate test period for the plant and depreciation impacts of the turbine upgrade projects. For most components of the Company's filing, Gulf utilized a test period consisting of the twelve months ending December 31, 2012. For the two turbine upgrade projects that are being placed into service in May and December, 2012, the Company has utilized a test period consisting of a single point in time as of December 31, 2012. In determining the overall rate of return to apply to the investments or rate base, the Company is using a capital structure and cost of debt and preferred stock based on the average test year amount. The accumulated deferred income taxes included in the capital structure are also based on the average 2012 test year. The Company has essentially used a mix of two separate test periods in determining revenue requirement in its supplemental testimony proposal.

Q. **CAN YOU GIVE SPECIFIC EXAMPLES OF HOW GULF'S PROPOSAL MAY RESULT IN A MISMATCH OF THE REVENUE REQUIREMENT COMPONENTS?**

A. As previously mentioned, Gulf has indicated that the turbine upgrade projects will increase capacity from the units by 30 MW. While this may offset purchased power costs, it also can be used to serve additional customers on Gulf's system. The revenue projections included in the filing are based on the projected customer levels and the projected sales for the 2012 test year.

Additionally, the turbine upgrades being placed into service in 2012 may also qualify for 50% bonus depreciation. The impacts of bonus depreciation on the accumulated deferred income taxes, which are included in rate base at zero cost, are based on projected average test year balances and not an annualized year-end level. If the two turbine upgrades occurring in 2012 qualify for bonus depreciation treatment, significant tax benefits would result. Gulf has not annualized the tax benefits in its supplemental filing.

Q. WOULD ACCEPTANCE OF YOUR APPROACH PREVENT GULF FROM RECOVERING THE COSTS OF THE TURBINE UPGRADES?

A. No. The answer to this question gets to the essential difference between base rate proceedings and cost recovery clauses, which are examples of the "single issue ratemaking" to which I referred near the beginning of my testimony. Cost recovery clauses are "item specific." In a cost recovery clause, as implemented by this Commission, the cost associated with a particular item that is deemed eligible for the clause is quantified on an annual basis, is embedded in a "recovery factor" that changes yearly, and is "trued up" if necessary to ensure the item (and, in the case of capital items, associated return) is recovered precisely. In a base rate proceeding, by contrast, the Commission takes into account the total operations of a utility. It uses a representative test year, typically a future test year, to quantify overall revenue requirements, establishes a range of rate of return that it deems reasonable, and sets rates designed to generate revenues that will give the utility the opportunity to earn a fair rate of return. I note that the Commission already has allowed Gulf (as it allows other utilities) to use a future (or projected) test period. This in itself is advantageous to the utility. By asking the Commission to annualize the revenue requirements of a plant item added in the projected test period, Gulf simply pushes too far in the direction of utility-favoring mechanisms. Just as the Commission does not annualize the impact of an amortization that will cease during the test year or a retirement that will occur during the test year, the Commission should not distort the test year rate base to annualize the additions to the turbine upgrade projects.

Q. **IF THE COMMISSION ACCEPTS GULF'S PROPOSED TREATMENT OF THE TURBINE UPGRADE PROJECTS, ARE ANY ADDITIONAL ADJUSTMENTS NEEDED?**

A. Yes. It is my recommendation that the proposed annualized treatment of the two turbine upgrades projected to be placed into service in 2012 be denied and that recovery be based on the traditional average test year approach. However, if the Commission instead agrees with one of Gulf's proposed recovery methods that allows for recovery of the annualized investment level, then an additional adjustment to annualize the impacts on accumulated deferred income taxes should also be made. This can be done through two different methods. The first method would annualize the amount included in the deferred tax component of the capital structure associated with the tax timing differences for the two turbine upgrade projects being placed into service in 2012. This would reduce the overall rate of return. The resulting revised capital structure would then be used in this case.

Under the second approach, the difference between the annualized amount of accumulated deferred income taxes caused by the two turbine upgrade projects that are being placed in service in 2012 and the average balance already incorporated in the filing could be reflected as a reduction to the turbine upgrade rate base balance. This would be the simpler approach.

Q. HAVE YOU CALCULATED THE INCREASE IN OPC'S RECOMMENDED REVENUE REQUIREMENT CAUSED BY INCLUDING THE TURBINE UPGRADES IN GULF'S BASE RATE REVENUE REQUIREMENTS?

A. Yes. Revenue requirements should be increased by $3,273,000 on a jurisdictional basis to include the turbine upgrades in base rates resulting from this case. This would allow for recovery of the costs in rates based on the traditional average test year methodology. A side by side comparison of the recovery using the average test year approach presented by Gulf in Exhibit No.__(RJM-3), Schedule 1, of $3,768,000 and my recommended allowance of $3,273,000 is presented below:

(amounts in thousands)	Per Gulf Amount	Per OPC Amount
13MA Jurisdictional Rate Base, per Gulf	$ 28,020	$ 28,020
Required Rate of Return	7.05%	5.89%
Jurisdictional Carrying Cost	$ 1,975	$ 1,649
Plus: Jurisdictional Net Operating Income	330	354
Total	$ 2,305	$ 2,003
Times: Net Operating Income Multiplier	1.634607	1.634173
Revenue Requirement Impact	$ 3,768	$ 3,273

The difference between the OPC recommended increase in revenue requirement caused by the turbine upgrade projects under the traditional test year methodology of $3,273,000 and that reflected by Gulf of $3,768,000 is due to OPC recommending a different rate of return and net operating income multiplier than that proposed by Gulf. The interest synchronization impacts, which are included in the line titled "Plus: Jurisdictional Net Operating Income" above, also differ due to the revised weighted cost of debt rates recommended by the OPC. These differences were discussed in the OPC's direct testimony in this case.

Q. ARE THERE ANY ADDITIONAL ISSUES PRESENTED IN MR. MCMILLAN'S SUPPLEMENTAL TESTIMONY THAT NEED TO BE ADDRESSED?

A. Yes. At page 7, lines 12 – 21 of his supplemental testimony, Mr. McMillan indicates that if the turbine upgrade projects are included in rates based on the 2012 test year 13-month average balances: "In order to recover its cost of providing service, Gulf would be forced to consider filing a separate limited proceeding during 2012 to request that these costs be included in rates beginning in January 2013." This would be the equivalent of single-issue ratemaking that should be rejected outright. As previously indicated in this testimony, there are no compelling reasons to treat the turbine upgrade projects differently than any other capital additions that would typically occur during a test year. Upgrades to plant that improve efficiency or performance are not unique isolated events that should trigger special ratemaking treatment. If Gulf evaluates its financial position in future periods and determines that a modification in base rates is necessary, it has the opportunity to file another base rate case that would consider all of the components that are considered in setting base rates.

Q. DOES THIS COMPLETE YOUR PREFILED SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, it does.

BY MR. McGLOTHLIN:

Q. Ms. Ramas, would you summarize your testimony for the Commissioners?

A. Yes. Good morning, Commissioners, Counsels. In my testimony, I present the overall revenue requirement that's recommended by the Office of Public Counsel in this case. This includes the impact of the adjustments I'm recommending as well as the cost rates and overall rate of return recommended by Dr. Woolridge, as well as adjustments recommended in the testimony of Mr. Schultz and Ms. Dismukes in this case.

Since the time of the calculations presented in my direct testimony, the Crist Unit 6 and 7 turbine upgrades have been moved from the energy cost recovery clause into consideration of base rates in this case, and I address that in my supplemental direct testimony. Within that testimony, I recommend that those projects be included based on the traditional average test year methodology. It's my opinion that there is no justification or reason to treat these any differently than any other projects that are included in base rates in this case.

I will now address a few of the adjustments in my testimony. I don't have time to go through all of them, but there are certain key ones I would like to draw the Commission's attention to.

One area I address are the labor related expenses in this case. Gulf has projected a substantial increase in the employee complement in this case, going from 1,330 employees as of December 31, 2010, to a projected level of 1,489 employees in the test year in this case. This is an increase in the employee complement that's being requested of 159 employees or a 12 percent increase.

And not only do they assume that all those increases will be added by the beginning of the test year, but they have also assumed in their filing that they will remain filled throughout the test year and there will be no employee vacancies throughout the test period. I do not think that's a realistic assumption, and it's inconsistent with past history for Gulf. In each and every year since the last rate case, the actual employee complement has been far below the budgeted level. In 2002, the average actual employee complement was 62 positions below the budgeted level. In 2006, the average complement was 96 less than budget, and in 2007 it was 83 less. As of June 30th of this year, they were 124 below their budgeted employee complement.

And I also demonstrate within my exhibits that the total employee complement at Gulf Power since the time of the last rate case has been fairly steady. It isn't until this rate case that they projected this significant increase.

What I have recommended is that based on the application of the historic average by which Gulf has been under budget in its employee complement to the requested test year employee level, that that be applied to their requested positions. This would result in a recommended increase in the employee complements that are reflected in base rates from the December 31, 2010 level to the test year of 68 positions, which is 5 percent higher than what they had as of the end of 2010. And it's also higher than the actual employee level they had as of June of this year.

The next area I wish to address is the incentive compensation program costs. The company has four separate incentive compensation programs, three of which are long-term in nature, one of which is short-term. It's my position that all of these programs focus on things that benefit Southern Company's shareholders and not the ratepayers. The three long-term programs are focused entirely on the earnings and stock costs of Southern Company, and it's only senior level positions that participate in these programs. Thus, I recommend that they be funded by the shareholders.

The third one is the short-term incentive compensation plan, which is the performance pay program. Under this program, there is nothing at all paid under the plan if Southern Company's earnings per share don't exceed the prior year dividends paid to Southern Company's investors. Thus, if that trigger isn't met, there's no payout under that plan. Once that is met, there are three areas that are weighted in the plan. One-third of the plan weighting is tied directly to the parent company or Southern Company's earnings per share, one-third is based on Gulf's return on equity, and then one-third is based on operational goals. I've recommended that these amounts be funded by the shareholders, as the primary focus and the trigger itself for the plan is based on those shareholder interests and not customer interests.

Thank you.

CHAIRMAN GRAHAM: Thank you.

MR. McGLOTHLIN: Ms. Ramas is available for cross-examination.

CHAIRMAN GRAHAM: Any intervenors who have a contrary position?

MS. KAUFMAN: I have no questions. Thank you.

CHAIRMAN GRAHAM: Okay. Staff.

MR. YOUNG: Staff handed out an exhibit yesterday, a late-filed exhibit to Ms. Ramas's deposition and I just wanted to inquire if Mr. McGlothlin has an objection to this deposition being moved into the record.

MR. McGLOTHLIN: We have no objection to the late-filed exhibit. We maintain our objection to the transcript itself.

MR. YOUNG: No problem. And, Mr. Chairman, that was handed to you along with Mr. McGlothlin's exhibits, and we ask that it be identified and given its own separate number and moved into the record at the appropriate time.

CHAIRMAN GRAHAM: We will label this as 204. And do you have a title for this one?

MR. YOUNG: Yes, sir. Late-filed Exhibit Number 2 to the deposition of Donna Ramas.

(Exhibit Number 204 was marked for identification.)

CHAIRMAN GRAHAM: Any questions?

MR. YOUNG: In lieu of that, Mr. Chairman, no questions.

CHAIRMAN GRAHAM: Commissioners? Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman.

Good morning.

THE WITNESS: Good morning.

COMMISSIONER BROWN: Can you -- you recommended that the Commission reduce the annual reserve accrual to $600,000. Can you elaborate a little bit on why you're recommending that?

THE WITNESS: I'm sorry. Could you point me to that?

COMMISSIONER BROWN: Certainly. It's on page 26 your supplemental, I believe.

Oh, I'm off. I'm off. Strike that.

THE WITNESS: Okay. Thank you.

COMMISSIONER BROWN: Let me just find my notes real quick.

On page 30 of your direct filed testimony, you go into the stock option program that the company has.

THE WITNESS: Yes.

COMMISSIONER BROWN: And you analyze it a little bit. Can you provide to the Commission what benefit customers get from having the stock option program in place?

THE WITNESS: In my opinion, customers get no benefit from those programs. Typically, those type of long-term incentive programs are designed to make sure that senior level employees and executives are focused on meeting shareholder goals, so in my opinion, there's no benefit to the ratepayers from these programs.

COMMISSIONER BROWN: Similarly, with regard to the performance share program, what benefit to the customers are they deriving?

THE WITNESS: In my opinion, none. That program, the payouts under the program are calculated based on the three-year total shareholder return versus the industry peers of Southern Company. In my opinion, ratepayers don't receive any benefit from that.

COMMISSIONER BROWN: Okay. And right now you're recommending a disallowance of rate case expenses. Can you please elaborate to the Commission on what you are recommending?

THE WITNESS: Yes. I've recommended that several items that were included within the requested rate case expense be removed. The majority of what I'm recommending for removal are the costs that are being allocated as part of rate case expense from Southern Company Services to Gulf. The company has indicated that these are amounts that are being direct charged from Southern

Company Services to Gulf.

There has been no demonstration that these same type of costs from Southern Company Services aren't already considered in base rates. Within base rates, there are costs that have been incorporated for allocations from Southern Company Services. And in the test year in this case, the company has included costs that are coming from Southern Company Services. I haven't seen any clear demonstration that these costs from Southern Company Services that are being included in rate case expense are incremental from those costs that are either already in base rates or are being factored into the test year in this case.

I've also recommended that overtime costs be excluded. Overtime costs are currently considered in the existing base rates. They're also being considered in the test year. It's my opinion these aren't incremental costs that aren't already considered in rates, so I recommended those be removed.

And I also raised a concern in my testimony with the number of people Gulf anticipated being here for all five days of hearings. I believe it was somewhere in the range of 60 to 65 people. I felt that it was excessive to have every witness here for every day of hearing with multiple assistants for each of those employees.

COMMISSIONER BROWN: Thank you. That's all.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I have a few questions.

You recommended adjusting the employee number to better reflect the vacancy rate that they have had in the past; is that correct?

THE WITNESS: Yes, to reflect -- and it's not just vacancy. It's the fact that they never achieved the budgeted level of positions that they have. So I guess it goes beyond a typical vacancy where you're just assuming there's a lag in hiring. It's my opinion that they're not likely to hire all those positions, so I've recommended that the amount requested in the test year be reduced to be more consistent with what has historically happened for Gulf.

COMMISSIONER BALBIS: Now, did you look into what employees -- the vacant positions, what the type of position was for those employees, either in the test year or previous years?

THE WITNESS: I've looked at all the testimony and rebuttal testimony filed by the company with regards to the positions. I'm not challenging any of those individual positions, but when the company goes through the budget process each and every year, their executives and management employees that prepare those budgets are expected to put in a request for a reasonable number of employees that they feel are justified, but yet they don't hire all of those.

So that's why I've recommended that in the test year, it's not likely that they're now, after nine or ten years of not filling all the budgeted positions, that they will now do so. So I'm not challenging the need for any of the employees they've requested.

COMMISSIONER BALBIS: But wouldn't you agree that some of those employees may be employees that are necessary to run one of their power plants, for example, so if they do not have their own employees filling that position, they would have to go out for either contract labor or have additional overtime costs for their current employees?

THE WITNESS: They may have some additional costs for outside contractors associated with that.

In my adjustment, I'm only adjusting the O&M portion that's included in expense. A lot of what you would use outside contractors for would be items such as construction projects. So, therefore, if they don't hire their own employees to do some of those construction projects, the full cost would still be included in the filing for the portion that's capitalized that goes into the addition of assets.

COMMISSIONER BALBIS: Okay. So are you recommending any adjustments to either a contract labor budget item or overtime line item, or just --

THE WITNESS: No, I'm not. There are overtime costs factored into the test year. And I don't -- I haven't seen any evidence provided by the company that if we don't hire this amount of employees, here's the amount of dollars we're going to incur for contract labor, so you need to add that.

They've just given a presentation showing, you know, each year here's our budgeted O&M expense, here's our actual O&M expense. But, you know, within the last four years during which they were considerably under their budgeted employee complement, their total O&M expense has been less than what they had budgeted in those years. So I don't agree that you have a dollar-for-dollar impact, that if you don't hire the employee, you have to give us dollars for outside contractors. I don't agree with that premise.

And I don't see anywhere where other costs are decreasing in 2012 because of the company adding these employees and bringing them in-house. In just about every cost area in this case, the amount of projected O&M expense in increasing. I don't see where the company had removed costs associated with hiring additional employees.

COMMISSIONER BALBIS: Okay. And the last question on this topic: So in the test year, what was their vacancy rate, what percentage? I believe that's in your testimony.

THE WITNESS: Within the base 2010 year or -- because I guess we don't know what the vacancy rate is going to be in 2012, I've recommended that a rate of 6.8 percent, I believe it is -- let me check just to give you the correct number that I've recommended be applied for the vacancies.

Yes, I recommended that the calculation be based on the most recent five-year average, so a 6.1 percent assumption. And I applied that 6.1 percent to their requested level of 1,489 employees.

COMMISSIONER BALBIS: And you did not recommend an adjustment to either overtime or contract labor, because at that percentage, they were incurring those costs at the time; is that correct?

THE WITNESS: I'm not sure I understand the question.

COMMISSIONER BALBIS: Okay. So if you're basing it on the five-year average vacancy rate, the 6.8 percent, and during that time they had to be conducting operations, running the plant, running distribution and transmission systems, so they would have had to have contracted the additional labor they needed or incurred the overtime costs associated with having their employees work longer, is that why you are not recommending an adjustment to overtime, or are you just --

THE WITNESS: No. I just don't feel it's necessary. During the last five years, they have been under budget in their total O&M expense during the same time that they were below their employee complement that they had budgeted for.

And additionally, in preparing its case, it's up to the company to provide a reasonable budget and projection, and they provided amounts for labor. It's my opinion that those projected labor dollars are overstated.

COMMISSIONER BALBIS: Okay. Now, to change gears a little bit, to follow up on Commissioner Brown's questions on the incentive programs, I just want to clarify the PPP program. On page 33 of your testimony, I just want to make sure that these numbers are correct. But according to your testimony, the award percentages range from 5 percent of base pay all the way up to 60 percent of base pay; is that correct?

THE WITNESS: Actually, they're as low as 5 percent of base pay for the union level employees, and then they increase from anywhere to -- from that 5 percent, they go up to 10 percent for grades 1 through 5 employees. And then they increase as the employee level increases, so that by the time you get to the upper executive level, it's 60 percent.

COMMISSIONER BALBIS: So the percentages range from 5 percent to 60 percent?

THE WITNESS: Yes.

COMMISSIONER BALBIS: Okay.

THE WITNESS: And again, that's at the target level.

COMMISSIONER BALBIS: Okay. And yet on page 35 -- I believe it's page 35 -- you recommend that you disallow all of the costs associated with the PPP program; correct?

THE WITNESS: Yes, I recommend that they be excluded from base rates and funded by shareholders.

COMMISSIONER BALBIS: Okay. But on page 35, line 11, you indicate that one-third of the plan targets Gulf Power's operational goals.

THE WITNESS: Yes, but I still recommend that all the costs be excluded, because before even getting to that point, they have to reach that trigger that's based on Southern Company's earnings per share and on that earnings per share exceeding the dividends paid in the prior year by Southern Company.

COMMISSIONER BALBIS: Okay. Thank you. I have nothing further.

CHAIRMAN GRAHAM: Redirect?

MR. McGLOTHLIN: No redirect. A couple of what I think will be minor housekeeping items, if I may.

Ms. Ramas indicated that she had accepted Gulf's explanation of the SGIG and no longer wished to adjust that. She did have occasion to revise the schedule that reflects that, and we have distributed that. I failed to get an exhibit number. If there's no objection, I would like to offer that in conjunction with her testimony so that the exhibits are consistent with that testimony.

CHAIRMAN GRAHAM: We'll give it Exhibit Number 205. And we'll just call it Revised Schedule B-2 and B-3.

MR. McGLOTHLIN: Yes. Thank you.

(Exhibit Number 2-5 was marked for identification.)

MR. McGLOTHLIN: Yes. Thank you.

And the other matter I wanted to mention was this. Commissioner Brown, I believe you started to pose a question about the storm accrual to Ms. Ramas. Our witness Mr. Schultz is the one who developed that adjustment, and she incorporated it in the calculations.

COMMISSIONER BROWN: Thank you. I'm aware of that. Thank you.

MR. McGLOTHLIN: With that, I move Exhibits

35, 36, and 205.

CHAIRMAN GRAHAM: We'll move exhibits 35 and 36 on page 10, and -- 204 and 205?

MR. YOUNG: I'll move 204.

(Exhibit Numbers 35, 36, 204, and 205 were admitted into the record.)

CHAIRMAN GRAHAM: Thank you, Ms. Ramas.

THE WITNESS: Thank you.

(Transcript continues in sequence in Volume 9.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1288 through 1522 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 17th day of December, 2011.

Mary Allen Neel

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