BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080317-EI

In the Matter of:

PETITION FOR RATE INCREASE BY TAMPA
ELECTRIC COMPANY.
____/

VOLUME 14

Pages 2152 through 2332

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
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REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

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CHAIRMAN CARTER: We are back on the record. And when we left, I believe it's -- Mr. Moyle, you're up.

MR. MOYLE: Thank you. Thank you, Mr. Chairman. We would call witness Tom Herndon to the stand, and he has not yet been sworn.

CHAIRMAN CARTER: Okay. Any of the other witnesses, Mr. Pollock and Mr. O'Donnell and Mr. -- now Mr. Murry has been sworn. But if Mr. Pollock and Mr. O'Donnell, are they here? Would you please stand so we can swear you in as a group.

(Witnesses collectively sworn.)

Thank you. Please be seated.

JOHN TOM HERNDON

was called as a witness on behalf of the Florida Industrial Power Users Group, the Mosaic Company, and the Florida Retail Federation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MOYLE:

Q Good morning, Mr. Herndon. Would you please state your full name for the record.

A Yes. My full name, excuse me, my full name is John T. Tom Herndon.

Q And are you the same Tom Herndon who prepared and filed 20 pages of direct testimony on behalf of FIPUG and the

Florida Retail Federation in this case?

A Yes, I am.

Q And a copy of your resume was provided with your testimony; correct?

A Correct.

Q Okay. That is for the record presently marked as Exhibit 54.

Mr. Herndon, if I were to ask you the questions that are contained in the direct testimony that you prefiled, would your answers to those questions be the same?

A Yes.

Q Have you prepared a summary of your testimony?

CHAIRMAN CARTER: Mr. Moyle, you want to enter it into the record?

MR. MOYLE: Yes. Yes, please. I would like to enter Mr. Herndon's prefiled testimony with the exhibit into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of the witness will be entered into the record as though read. And for the record, recognition of, for identification purposes, Exhibit Number 54.

(Exhibit 54 marked for identification.)

Introduction

Q. Please state your name and where you reside.

A. My name is Tom Herndon and I live in Tallahassee, Florida.

Q. On whose behalf are you providing testimony in this matter?

A. I am testifying on behalf of entities which represent electric customers of Tampa Electric Company. Specifically, I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG), the Mosaic Company (Mosaic), and the Florida Retail Federation (FRF). FIPUG represents the interests of a number of large industrial businesses, who take service from Tampa Electric Company (Tampa Electric). Mosaic is a large company that mines phosphate and produces fertilizer and receives electrical service from Tampa Electric. FRF is a trade organization with over 10,000 retail business members, many of whom take service from Tampa Electric.

Summary of Recommendations

Q. What recommendations do you make to the Commission in your testimony?

A. After discussing current financial conditions, I recommend that:

- The Commission adopt a Return on Equity (ROE) for Tampa Electric of 7.5%; the 12% ROE Tampa Electric seeks is out of line with current market conditions and its low risk profile;
- The Commission not place undue reliance on computer models to determine ROE in these unusual economic times; and

- The Commission reject the notion that somehow a higher ROE for Tampa Electric benefits ratepayers.

Professional Experience in the Financial Arena

Q. Please provide a description of your past financial experience.

A. I have enjoyed a long career in public service in the state of Florida that started in 1969. I have attached my resume as Exhibit No. ___ (TH-1) to my testimony. However, I'd like to briefly summarize some roles in which I have served the state that are particularly relevant to my testimony in this case.

I was Staff Director for the House of Representatives Appropriations Committee from 1978 to 1980. After that, I served for nearly five years as the Director of the Governor's Office of Planning and Budgeting. In that position I was responsible for advising the Governor on a multitude of budgeting and financial matters.

I served as Chief of Staff to Governor Graham and Governor Chiles. I served on the Florida Public Service Commission from 1986 to 1990. In the early 1990s, I was the Executive Director of the Florida Department of Revenue. My last position with the State of Florida was as Executive Director of the Florida State Board of Administration from 1996 until 2002.

Q. What do you do presently?

A. I work part time providing consulting services for a handful of clients and serve on select boards.

Q. Can you describe your duties and responsibilities as the Executive Director of the Florida State Board of Administration in more detail?

A. I was selected by the Governor, Comptroller and Treasurer, who were the Trustees of the State Board of Administration ("SBA"), to lead and manage the state's pension fund as well as approximately one dozen other investment accounts. As Executive Director of the SBA, I was responsible to the Governor and Trustees, as well as the beneficiaries of the state's pension fund, for prudently managing the fund's assets.

During the six years I led the SBA (from 1996 to 2002) the SBA had over $100 billion dollars under active management and ranked in the top ten largest (based on assets under management) pension funds in the world. As SBA Executive Director, I was charged with overseeing and managing the state's investment policies and practices as well as providing regular financial reports to the Governor and the other trustees.

Q. Please discuss your financial expertise, particularly the expertise you gained during your service as Executive Director of the SBA.

A. I have gained financial experience and expertise during the course of my professional responsibilities. While serving as Staff Director of the Florida House of Representatives Appropriations Committee, I gained considerable expertise in the state budgeting processes, including how the state uses debt, current revenue or reserves to fund state government operations. I also gained a thorough understanding of the business of Florida's state government, its functions and how it funds its operations.

When I served as a Public Service Commissioner, I gained financial expertise in regulating and reviewing financial matters involving public utilities, including electric utilities, water and waste water utilities, and telecommunications companies.

When I served as the Director of the Office of Policy and Budget under Governor Graham, I was involved with many financial matters, including preparing and recommending a complete state budget to the Legislature, advising the Governor on a broad range of economic issues, and working with state economists on future economic projections. During this time, I also had regular contact and interaction with other state offices, such as the Division of Bond Finance, concerning the issuance of state bonds. I met with rating agencies to provide input for risk analysis associated with state debt ratings.

When I served as Executive Director of the SBA, my central focus was management of the state's $100 billion pension fund and ensuring a reasonable return on invested dollars. During this time, I met and interacted with Wall Street investment advisors, fund managers, key executives of publicly traded companies, rating services, and others who were involved in a host of financial matters. I also gained a thorough understanding of risk and its relationship to reasonable returns. During this period, I also chaired the Council of Institutional Investors and interacted with the Securities and Exchange Commission and Congress on Pension Reform Assessment. I also served on the Pension Advisory Committee to the New York Stock Exchange.

Q. Are you still involved with the SBA?

A. No, not in any official capacity. However, I was recently appointed by Governor Crist, Chief Financial Officer Sink, and Attorney General McCollum to a committee which was charged with soliciting, interviewing and recommending candidates to serve as the new SBA Executive Director. In addition, I generally keep up with SBA activities and policies.

Q. Are you currently involved in managing and investing money?

A. Yes.

Q. Please describe your current involvement.

A. Currently I serve on the Board of Directors of the Helios Education Foundation. I am the Treasurer and Chairman of the Finance and Investment Committee. This Committee is responsible for managing and investing approximately $500 million dollars in a perpetual foundation portfolio. We manage domestic and international equities and fixed income exposure and until the recent downturn, were quite successful.

In addition to my work with Helios, I also serve on the Finance Committee of Capital Health Plan, a large Tallahassee-based Health Maintenance Organization (HMO). As a member of that committee, I help oversee the investment of over $200 million in assets.

Purpose of Testimony

Q. What is the purpose of your testimony?

My testimony focuses largely on financial issues, including the closely related issues of risk, investor expectations, the current economic climate, and the fact that Tampa Electric operates as a monopoly provider of an essential service, effectively free of competition, in a very low risk regulatory environment. More specifically I will discuss how these factors should impact the return on equity that the Commission will authorize for purposes of setting Tampa Electric's rates in this case.

My testimony will also discuss the models Tampa Electric witness Donald Murry references in his direct testimony and why those models should be given less weight in today's economic climate. I will comment on the suggestion of Tampa Electric witness Susan Abbott that approval of the rate increase Tampa Electric seeks should result in an A rating from the rating agencies and why this view is erroneous.

Finally, I will discuss the notion that permitting Tampa Electric to earn a higher return on equity will somehow benefit ratepayers by reducing its borrowing costs. I will explain why this is not the case.

Current Market Conditions

Q. Please comment on current financial market conditions as it relates to Tampa Electric.

A. As witness Murry pointed out, we are in the midst of severe economic upheaval. However, many of the economic factors he identified in his direct testimony have changed since his testimony was filed. For example, interest rates are at an all time low and no sign of increases are in sight. Oil prices have fallen to below $60 per barrel -- drastically below the rate witness Murry cites. Consumer confidence continues to fall and unemployment continues to rise.

While there may be some reasons to believe that the U.S. economy and the world economy will be well on their way to recovery by sometime in 2009, regardless of whether this turns out to be the case or not, the fact that Tampa Electric has a very high degree of revenue certainty and very low risk makes its common stock an attractive investment.

Q. Have current economic conditions affected the credit markets?

A. Yes, but while credit markets are in turmoil for some borrowers, funds are available at reasonable rates for high quality borrowers. World-wide recognition of the economic catastrophe has occurred and as a result virtually every developed nation has adopted some form of an economic bailout package. The United States led this effort with its $700 billion dollar bailout plan. While the volatility in the markets continues, there are some reasons to feel more confident.

Q. Does the economic picture impact investment expectations?

A. Yes. Investors as a rule seek safety and security in times of economic stress and that is certainly true today. Clear evidence of that trend can be seen in the higher value investors have put on utility stocks and debt. While all sectors of the U.S. economy have been damaged in the recent upheaval, utility stocks have been treated better overall than the broader indexes. Utility debt ratings have also been treated better than many other sectors. This preferred treatment for utility debt reflects the higher regard investors have for the utility sector. The proverbial "flight to quality" once again seems to be in play and utility companies are beneficiaries of this trend, because, as noted above, money is available to well-regarded borrowers. Quite a bit of anecdotal evidence exists to show that for these well-regarded borrowers, lenders are stepping up to make loans at competitive rates --- certainly, much below the 12% ROE level Tampa Electric has requested.

Q. On what do you base this view?

A. As I mentioned, I remain active in providing advice and recommendations regarding managing and investing funds. It is my observation that well-qualified borrowers can obtain credit at reasonable costs. That is not to suggest that for every borrower credit can be easily obtained; however, for an organization as well-regarded as Tampa Electric, especially where the company is a monopoly that operates in a very low risk regulatory environment, raising both debt and equity capital should not be overly problematic.

Q. In your opinion, should Tampa Electric be able to secure debt at competitive rates?

A. Yes. Tampa Electric enjoys ratings from the major rating agencies which qualifies its debt as investment grade. Investors are more comfortable with investment grade debt, while many investors shy away from the debt products of companies that do not have investment grade ratings.

Q. In your opinion, should the Commission feel confident that Tampa Electric can obtain equity capital, i.e., that investors will invest in TECO Energy's common stock, if the Commission sets Tampa Electric's revenue requirements and rates using an authorized rate of return on equity with a midpoint of 7.5%?

A. Yes. The Commission should feel completely confident that Tampa Electric can raise needed equity capital with its revenues and rates set using an ROE of 7.5%. This is because investors understand the fundamental security of their investments in Tampa Electric and other Florida utilities. That security comes from the very low risks that Tampa Electric faces with its monopoly position as well as the fact that it provides a necessity, with the routine, secure, virtually certain recovery of well over half its total costs through cost recovery clauses.

Tampa Electric's Risk As A Regulated Utility

Q. Please comment on the relative risk confronting Tampa Electric, as a regulated utility, when compared to other business sectors.

A. The risk that Tampa Electric faces is much less than businesses in other sectors. Due to its monopoly status, Tampa Electric does not have to compete for customers in an open market. It enjoys a defined geographic market and has a government-created and government-protected monopoly in that market. And for the most part, its customers are captive – if they want electric service, they must buy it from Tampa Electric. Indeed, Tampa Electric witness Murry references "market power" as the basis for utility regulation. Such monopoly power greatly reduces the risk Tampa

Electric faces. Obviously, Tampa Electric does not compete with other electric companies (or anyone else) to serve its customers.

In contrast to the market position of Tampa Electric, we are all familiar with the effects and risk of competition in competitive business sectors. For example, DHL is exiting the parcel delivery business in the United States, in part, due to competitive pressures from UPS and FedEx. In the auto industry, in part due to multi-national competition, U.S. companies are suffering and seeking funds from Congress to sustain their operations. The national electronic retailer, Circuit City, has recently filed for bankruptcy protection.

The examples of competitive risk that most U.S. businesses face are countless; however, this is not the case with Tampa Electric. Too a very large extent, Tampa Electric faces no market driven competitive risks. Investors and Wall Street are well aware of this. This is the key reason that utility stocks and bonds have long been a safe haven for investors.

Q. Doesn't Tampa Electric still have to address and manage risk?

A. Yes. Tampa Electric, as well as other regulated monopoly utilities, has to manage risk. The utility business is not completely risk free. For example, Congress could enact additional environmental requirements that could affect the electric utility industry. My point is that Tampa Electric's risk profile is reduced significantly because Tampa Electric does not face competition in the marketplace and because the current regulatory system in Florida ensures that it recovers a very high percentage of its total costs on a current basis through the various "cost recovery" or pass-through clauses.

Q. Does this reduced risk affect investment expectations?

A. Yes. Reduction in risk is tied to market/investor expectations of return on investment or return on equity. Less risk equals lower return expectations. As discussed above, in today's market environment, investors want: quality, reduced volatility, security, and reasonable prospects for safety going forward. Very few stocks or bonds offer this combination of benefits, other than a quality utility like Tampa Electric.

Q. Are you familiar with the regulatory framework in which Tampa Electric operates?

A. Yes, I am directly familiar with the regulatory environment in which Tampa Electric operates due to my tenure as a Public Service Commissioner.

Q. How Tampa Electric's costs currently recovered?

A. A significant portion of Tampa Electric's annual operating expenses are recovered through special clauses rather than through base rates. While I do not wish to suggest that I am an expert in the detailed operation of all of the current regulatory tools the Florida Commission uses, many of them – such as the fuel adjustment clause -- were in place during my tenure on the Commission.

It is my understanding that currently fuel expenses and purchased power expenses are recovered through the fuel clause; capacity costs are recovered through the capacity cost recovery clause; energy conservation costs are recovered through the conservation cost recovery clause, environmental costs may be recovered through the environmental clause; and hurricane expenses may be recouped though a hurricane recovery clause. In addition, gross receipts taxes and franchise fees are recovered as line items on customer bills, thus eliminating the risk of recovery for those items as well. These recovery mechanisms further reduce the risk Tampa Electric faces and lessen the risk of a prospective investor.

Billions of dollars flow through these clauses every year, and Tampa Electric has virtually no exposure to any risk of non recovery for these expenses because they are directly picked up by the ratepayers. Even when such expenses increase, Tampa Electric has the ability to seek a mid-course correction and recover such actual and projected cost overruns in between annual fuel adjustment proceedings. Thus, given the reduction in risk, there should be a commensurate reduction in the expected return on equity.

Q. What is your understanding of how the investment community views this regulatory framework?

A. In addition to serving as a Florida Public Service Commissioner, I have kept abreast of the Florida regulatory environment as someone charged with managing money. The investment community views the Florida regulatory environment quite favorably. The Florida Commission is viewed as responsive to the needs of the entities it regulates and has numerous mechanisms in place to prevent "regulatory lag." Witness Abbott's testimony confirms this point. Ms. Abbott notes in Exhibit 3 to her direct testimony that no other Commission in the country is ranked more favorably than the Florida Commission.

Q. Does this view of the Florida Commission affect Tampa Electric's risk profile?

A. Yes and it reinforces the fundamental point I made above. Tampa Electric operates in a reduced risk environment. This reduced investor risk translates into lower ROE expectations. Simply put, the favorable regulatory environment and Tampa Electric's reduced risk argues against the inflated 12% ROE Tampa Electric seeks.

Q. What about the suggestion that the Commission has to keep Tampa Electric's authorized ROE at a high level to ensure that investors continue to view Tampa Electric as a low-risk investment that they are willing to invest their equity capital in?

A. In my opinion, such a suggestion is misplaced and overstated. The Commission already ensures that Tampa Electric operates in a low-risk environment that ensures Tampa Electric of prompt, secure, and for all intents and purposes, certain recovery of well over half of its costs on a current basis, and Tampa Electric faces no competitive pressure and extremely low risk with regard to recovering its base rate revenues.

<u>Reasonable and Fair Return on Equity</u>

Q. What do you believe is a reasonable return on equity for Tampa Electric given your discussion above?

A. For many of the reasons I have discussed, I believe that a fair return on common stock equity in Tampa Electric Company would be in the range of 7% to 8%, with 7.5% being the midpoint of the range that the Commission should use for purposes of determining Tampa Electric's allowed revenue requirements and setting its retail rates.. My perspective on this issue is based on my experience and informed by the behavior of the stock market and those investment activities with which I am familiar, particularly in the public pension area.

Traditionally, most public pension funds have an actuarially required rate of return in the 7.5% to 8.5 % range. This allows for a real rate of return over inflation and for some modest growth while at the same time recognizing that withdrawals are occurring. In fact, the Florida State Board of Administration has long held to an 8% target and the other two foundation boards I have worked with have lower rate of return targets.

I realize that using these benchmarks is not the same as calculating the return through computer models. However, they serve as useful proxies for what is prevalent in the investment world. I dare say that Tampa Electric itself has similar targets for its internal assets under management as well as for its various pension funds.

The reason that I believe that a fair rate of return would use 7.5% as the midpoint is that for investors to reach the 8+% target requires a considerable equity allocation -- typically over 60% of the portfolio would have to be invested in equities. That strikes me as unnecessarily high for a regulated utility so the target I suggest reflects a more modest equity allocation.

Q. Does the SBA have a targeted return on capital it invests, and if so, what is that target?

Historically, the SBA seeks a target in the 8% neighborhood, but does so with a healthy mix of exposure to stocks, many of which are investments in companies faced with intense industry competition not seen in a business sector comprised of regulated electric utility monopolies, like Tampa Electric.

Q. How does the rate of return that you are recommending in this case compare to investment opportunities with less risk?

A. My recommended rate of return on equity compares very, very favorably to investments with lower risk. In financial management, we normally recognize the interest rate on long-term U.S. Treasury bonds as being the "risk-free rate." Recently, the interest rate on long-term – 30 year – U.S. Treasury bonds has been in the range of 4.0% to 4.3%; currently, the rate is below 4.0%. In the most practical terms, considering the very-low-risk environment in which Tampa Electric operates, as a monopoly with virtual certainty of recovering well over half of its operating costs and very little risk with regard to its base rates, a 7.5% return on equity is very favorable when compared to the "risk-free rate."

Stated differently, in practical terms, I am recommending a return on equity that is almost double the "risk-free rate." Again in practical, common sense terms, there is no way that Tampa Electric faces risks that justify any higher return than this.

<u>**Tampa Electric Witness Murry**</u>

Q. Have you reviewed the direct testimony of Tampa Electric witness Murry?

A. Yes.

Q. What is your view on the economic outlook witness Murry offers in his direct testimony?

A. While there are risks facing the credit and capital markets, the current picture and the forecast appear to be less dire than what witness Murry has assumed based on the information available to him at that time. Many view the fact that energy prices have fallen drastically and that interest rates, both short and long term, are lower, as signs that the economy may be improving. Inflation has moderated and with the Presidential election behind us, more certainty exists in the market. All in all, many of the economic indicators witness Murry relied upon have improved.

Q. Given the current market conditions you have discussed, what is your opinion regarding witness Murry's view that a return on equity of 12% is reasonable for Tampa Electric?

A. I have several thoughts regarding witness Murry's proposed 12% ROE.

First, many of the key underlying inputs to the formulas he used are no longer valid. Interest rates, oil prices, and inflation rates are all significantly below the levels witness Murry relied upon in his direct testimony. These decreases in rates and prices produce different investor conclusions about the relative risks and returns associated with Tampa Electric. If the witness intends to rely on mechanistic formulas, the inputs should at a minimum be current and valid.

Second, while I would not quarrel with witness Murry's formulaic approach in a **NORMAL** investment environment, that is not where we find ourselves today. Many analysts have likened the current economic upheaval to the financial devastation of the 1920s. While that may be an overstatement, there is no denying that we are not experiencing normal economic conditions. Given these unusual financial conditions, the mechanical application of formulas simply isn't adequate and should not be the beginning and ending of an ROE analysis. Common sense and a more thoughtful awareness of the market, coupled with some use of the technical analytics, is the approach called for today.

Finally, it is clear that a lender or an investor in today's climate would prefer to lend to a monopoly client with historically steady and stable growth, a guaranteed rate of return, substantial assets (in the form of infrastructure and rolling stocks), and the ability to recover a large degree of its operating costs annually through recovery clauses.

Rating Agencies and the Suggestion of Witness Abbott that Approval of Tampa Electric's Rate Request Will result in an A level Rating

Q. Have you reviewed the direct testimony of Susan Abbott?

A. Yes.

Q. Witness Abbott provides testimony regarding the rating agencies that follow Tampa Electric. Ms. Abbot suggests in her direct testimony at page 27 that "[a]pproval of TECO's requested rate increase should improve its credit metrics and in an A level profile." Can you comment on her conclusion?

A. In general, I agree with witness Abbott's testimony that improved credit matrices should improve the credit rating of a company and that should lower borrowing costs; however, I would make two points that modify this conclusion.

First, recent experience with organizations like Standard & Poor's and Moody's amply demonstrates that their work is art, not science. We are all too familiar with the various mistakes credit rating agencies have made that in part, led us to the current financial situation. To suggest that an "A" level profile will automatically result from a certain ROE takes too much for granted.

Second, while the actions and "grades" of the rating agencies can be valuable aides in investment and loan decisions, they are not the final answer. Common sense and thoughtful awareness of market conditions must also be considered. Tampa Electric's circumstances, including its low risk profile, the positive regulatory climate in Florida, the solid earnings path and stable growth forecast, do not support a 12% ROE.

Q. Some have suggested that allowing Tampa Electric a 12% ROE may benefit ratepayers by lowering borrowing costs. Do you agree with this?

A. No. I do not believe that allowing an elevated ROE benefits ratepayers. Any reduction in borrowing costs would likely be a slight incremental amount and would not offset the increased revenue requirements for ratepayers if a 12% ROE were to be authorized. Customers would be worse off because they would be paying higher rates than necessary. This is especially the case when, as the Commission is well aware, individual consumers, commercial consumers, and governmental and institutional consumers, such as school districts, are struggling to pay their electric bills.

And of course, the cost of electricity affects the production costs and the ability to compete of industrial consumers, such as FIPUG's participating companies.

In this time of great economic uncertainty, the Commission needs to be mindful of the role that energy costs play in the lives of individuals and businesses. With virtually every business straining to compete just to stay above water, and with many individual residential customers having to decide between paying their electric bills and buying food or prescriptions, approval of an excessively generous ROE is very short-sighted. The last thing the Commission should do is to further inflate (artificially I might add) energy costs which would cause even more dislocation in the business community and increase the costs to those businesses left standing.

Q. What is your recommendation to the Commission?

A. As noted above, I urge the Commission to evaluate the current economic climate and the stable regulatory environment in which Tampa Electric operates to arrive at a reasonable ROE. I would respectfully suggest that a fair return on equity is 7.5 percent. I further urge the Commission to temper its reliance on computer modeling with its knowledge of the current unusual financial conditions. I recommend that the

Commission reject any suggestion that approval of a high ROE somehow benefits ratepayers.

Finally, I strongly urge the Commission to consider its fundamental mission, which is to regulate utilities under its jurisdiction in the public interest. In this case, the public interest will be served by setting Tampa Electric's revenues and rates using a fair, compensatory rate of return on equity of 7.5%; this rate will, in my opinion, enable Tampa Electric to attract needed capital and provide Tampa Electric's equity stockholders with a very fair rate of return on a very low risk investment, while minimizing further economic stress on the citizens and businesses who must buy their electricity from the regulated monopoly provider, Tampa Electric Company.

Q. Does this conclude your direct testimony?

A. Yes it does.

CHAIRMAN CARTER: You may proceed.

MR. MOYLE: Thank you.

BY MR. MOYLE:

Q You've prepared a summary of your testimony?

A Yes, I have.

Q Would you please provide that summary to the Commission?

A Yes. Thank you.

My name is Tom Herndon and I am testifying on behalf of FIPUG and the Florida Retail Federation. I have experience in finance resulting from my service as Executive Director of the State Board of Administration, Director of the Florida Department of Revenue, State Budget Director and a variety of other professional positions. In addition, during the time that I spent as Executive Director of the State Board of Administration we managed approximately $100 billion in pension assets. I currently also serve on boards and foundations that have assets that are actively managed.

My testimony can be summarized into three major points. First, the Commission should adopt an ROE of 7.5 percent as opposed to the 12 percent requested by the company. My reasoning for this recommendation is as follows. TECO is a monopoly provider of electricity and not subject to any market-based competition. Thereby, eliminating competition is one of the risk factors that might conceivably support such an exorbitant request.

Secondly, interest rates are at all time low and market conditions argue in favor of access to capital and more reasonable returns on equity for investors.

Thirdly, because of a stable consumer, customer base and Commission-authorized pass-through of costs like fuel and others through cost recovery clauses over 50 percent of TECO's annual revenues are virtually guaranteed, thereby making an investment in TECO a very low-risk proposition for investors.

Fourthly, utility stocks have performed much better on average than the Dow, S&P 500 or the NASDAQ over the past years, bolstering the argument that they are a higher quality, more desirable investment for lenders and investors. Tampa Electric should be able to access capital markets with little difficulty given its history and the regulatory climate in which it operates.

Finally, state pension fund and pension fund accounts that TECO manages for its employees do not anticipate such a high ROE as that being sought in this case by Tampa Electric. If they do not anticipate and are not investing with an eye toward earning that much for investors, why should the Commission build into their base rates such a high return for investors in their stock or debt?

My second point is that statistical models such as CAPM and DCF are useful aids in calculating return expectations but they are not the sole determinants of reasonable return. Overall market and economic realities play a significant role in these decisions and common sense should not be ignored just because someone trots out a mathematical formula, especially one that is based on factors that are no longer valid.

Your decision about the return on equity is not a matter of artificial rule, models or formulas, but should be based on reasonable judgment based on consideration of all relevant facts. The Commission should pay particular attention to current market conditions which do not support an equity return of 12 percent. My judgment is that a return of 7 to 8 percent with a midpoint of 7.5 is appropriate.

My third and final point is that TECO should not be allowed to earn excessively high rates of return based on the premise that it will somehow help the taxpayer. TECO bases its argument in favor of an artificially high rate of return on the supposed benefits of easier access to capital and a higher credit rating, thereby lowering borrowing costs.

My response is to say as follows: First, good companies like TECO will have access to capital markets. We have seen as recently as December that TECO was able to extend a credit facility with no difficulty that I could discern whatsoever.

Secondly, neither TECO nor its witnesses can guarantee that a high credit rating, a higher credit rating will automatically result from a 12 percent ROE, which seems to be the chief reason why they're seeking the 12 percent figure.

Thirdly, TECO is seeking a high return on equity now that will increase rates to customers. They will see higher bills this summer. Customers will not see lower borrowing costs until the next rate case, which could be many years down the road. Also, future lower borrowing costs for the utility would not likely outweigh the higher rates that customers would have to pay immediately if higher rates are approved. An ROE of 12 percent will cost the customers much more in the long run than if they were authorized 7.5 percent and borrowed the needed capital at their current credit, credit rating level.

In closing, TECO's request for a 12 percent ROE is neither justified nor warranted by the facts or the arguments put forth by the company. The customers in TECO's service area should not be forced to pay an exorbitant ROE and further stress their family and business circumstances in this time of severe recession. In today's difficult economic environment a more appropriate return on equity is in the 7 to 8 percent range, and the Commission should be confident that Tampa Electric or TECO can raise adequate capital if the Commission sets the company's rates using an ROE in that range.

And, Mr. Chairman, before I close, I'd just like to thank you for the courtesy extended to me last night to allow me to go to the board meeting. Thank you.

CHAIRMAN CARTER: Thank you, Mr. Herndon. Even with your courtesy comment you still came in under five minutes. Perfect timing.

THE WITNESS: That's good.

CHAIRMAN CARTER: Excellent.

Let's hear from the company. Cross.

MR. HART: Mr. Chairman, we, in lieu of cross-examination, would like to insert Mr. Herndon's deposition into the record and ask that it be marked as an exhibit, identified as an exhibit.

CHAIRMAN CARTER: Okay. That will be -- staff, what number are we on?

MS. HELTON: I think it's 122, Mr. Chairman.

CHAIRMAN CARTER: Yeah. 122.

Okay. Any objections?

MS. CHRISTENSEN: No, other than it could have been done as part of the composite exhibit, but no objection at this point.

CHAIRMAN CARTER: Well, okay. No objection. Without objection, show it done.

(Exhibit 122 marked for identification and admitted into the record.)

Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Good morning, Mr. Herndon.

THE WITNESS: Good morning.

COMMISSIONER SKOP: Just a few questions. In your opening statement you used "exorbitant" in two contexts, but at least the context that I thought I heard is that you characterized your recommended ROE of 7.5 percent as an exorbitant request; is that correct?

THE WITNESS: No. I was talking about the 12 percent recommended or requested by the company.

COMMISSIONER SKOP: Okay. Okay. If the Commission were to adopt a 7.5 percent ROE as you suggested, what regulatory signal would a 400 basis point reduction send to the capital markets?

THE WITNESS: Well, Mr. Chairman or Commissioner, I'm not sure that -- I don't know what regulatory signal it would send. What I think it would send to the capital markets is a recognition of today's reality in the economic markets. I think a 7.5 percent return is more than double the risk-free rate in today's economic environment. It's a very reasonable return expectation that most investors would be pleased to have and --

COMMISSIONER SKOP: Well, let's talk about that return expectation. You mentioned that your, your, your analysis is based mostly in part on, on the expected return that a state pension fund would expect to receive.

Now you would agree, would you not, that different investors have different goals; is that correct?

THE WITNESS: Yes, indeed.

COMMISSIONER SKOP: Okay. So to the extent that a pension fund would make an investment, they would be looking for a conservative, very stable, risk-free investment; is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. So that would be seeking fixed income returns?

THE WITNESS: Well, most pension funds, including Florida's, has pretty high allocation to equities. So they have expectations of returns that are driven to some degree by risk.

COMMISSIONER SKOP: But when you mention pension fund, I mean, it's typically a fixed income looking investment, is that correct, for the most part?

THE WITNESS: Well, there's certainly a significant allocation to fixed income in most pension funds. Yes, sir.

COMMISSIONER SKOP: Okay. With respect to the recommended 7.5 percent ROE, would such action by the Commission result in the potential of an immediate credit downgrade to the utility with such an extreme measure?

THE WITNESS: I don't think anybody can give you a clear-cut answer to that question. I don't think that the company's witnesses can with confidence guarantee that a

12 percent return would give you, you know, a higher rating and I don't think that's --

COMMISSIONER SKOP: That's not my question. I'm not asking about what the company is seeking. I'm asking about what you've provided as an expert witness. And I'm asking in your professional opinion whether a 400 basis point reduction by this Commission adopting the requested 7.5 percent ROE could result in an immediate credit downgrade by the rating agencies.

THE WITNESS: Commissioner, I guess the only honest answer to your question is that anything could happen. But if I might go further.

COMMISSIONER SKOP: You might. That's fine.

THE WITNESS: Okay. I don't, I don't think that's very likely, to be perfectly honest. And I'm not sure that a downgrade by the credit rating agencies has as much significance as that action might have once had. I think investors are a great deal more skeptical about the credit rating agencies than they may have once been. But certainly that's a possibility and I would be naive to deny it.

COMMISSIONER SKOP: Okay. Well, let's go back a second for the institutional investors. I think that you mentioned that pension funds and other investors make equity investments, investments in equities in addition to, to fixed income investments.

Are you familiar with GE?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And you're familiar with their bond ratings, credit ratings?

THE WITNESS: I don't know what it is today, but I'm generally familiar with the company.

COMMISSIONER SKOP: So you would not know with your professional experience what GE's credit or bond ratings would be?

THE WITNESS: I don't off the top of my head.

COMMISSIONER SKOP: Okay. Are you familiar with the investment that Berkshire Hathaway just recently made in GE to the extent that they purchased preferred stock?

THE WITNESS: I'm aware that they did come in with a pretty significant investment and, as you said, got preferred stock.

COMMISSIONER SKOP: And are you familiar with the yield that was --

THE WITNESS: I don't recall. No, sir. I'm sorry.

COMMISSIONER SKOP: Subject to check, would you generally agree that there was a double-digit return or yield that they sought from making that equity investment?

THE WITNESS: Subject to check, yes.

COMMISSIONER SKOP: All right. Thank you. Just one final question. I guess Mr. Moyle asked a line of -- sorry. Excuse me. I'm sorry. Mr. Moyle had asked a line of questions to a prior witness suggesting that in lieu of traditional CAPM and DCF models that a more appropriate benchmark for the Commission to consider would be a recent rate case in terms of the authorized returns for the southeastern region. And in that regard, I'd like to get your thoughts on whether that would be appropriate. And too, secondly, the returns that were suggested that the Commission consider are significantly higher than your recommended return by almost 350 basis points, so I'd like to get some comment on that.

THE WITNESS: I'm not familiar with the specifics that Mr. Moyle proposed to another witness. But just following your thought for a moment, I think the Commission should weigh very carefully the information that is relevant coming out of other southeastern rate cases. Every company is different, every Commission is different, every state is different, every set of operating circumstances is different. You should take that into consideration, just as you should take into consideration CAPM and DCF models. They have some value. They also have some flaws. You know, you should also take into consideration the evidence that's all around us as it relates to the market and how it's functioning, and that's all I've been arguing is that the Commission should weigh all of these factors very carefully when you make a decision.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Anything further from the bench at this time?

COMMISSIONER ARGENZIANO: Yes.

CHAIRMAN CARTER: Commissioner Argenziano, you're recognized.

COMMISSIONER ARGENZIANO: I'll wait.

CHAIRMAN CARTER: Okay. You'll wait.

Okay. Ms. Christensen.

MS. CHRISTENSEN: Good morning.

THE WITNESS: Good morning.

MS. CHRISTENSEN: I have a few questions for Mr. Herndon.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Herndon, you would consider yourself an institutional investor; is that how you would consider yourself?

A Yes. In a sense -- certainly the SBA when I was there was a very large institutional investor, one of the largest in the world. Today the foundations that I'm involved with are institutional in nature. They're not individuals. Yes.

Q Okay. So you yourself are not coming at this from a financing, modeling, DCF and CAPM perspective; is that correct?

A I'm not what in Wall Street vernacular is called a quantitative analyst, no. I'm much more of a broad-based observer of the markets and have a certain modicum of financial expertise.

Q And I think you've testified today that you think or as an institutional investor your expectation is a 7 to 8 percent range; correct?

A Expectation is probably where I would, would quibble with you. I'm not sure that my expectation is that. But I think a 7 to 8 percent return on equity is a reasonable return on equity.

Q Okay. Would you as an institutional investor recommend to your clients that they invest in an electric utility if they had an ROE of 8.75 percent?

A Yes.

Q Okay. Now you would agree that Tampa Electric is a monopoly; correct?

A Yes.

Q And as a monopoly, in your opinion is Tampa Electric a safe and reliable investment?

A Yes.

Q Okay. And I think you may have touched on this earlier, but I just want to make sure that I'm clear. As a person who makes decisions for institutions on whether or not to invest, do you use credit agency reports in the determination of whether or not to invest in certain companies or stocks and bonds?

A Yes.

Q Okay.

A And if I might.

Q Certainly.

A There's no question that the credit rating agencies do a good job for investors. I think we probably are in an environment where their reliability is less pervasive than it once was, but they're still valuable inputs.

Q Okay.

MR. HART: Mr. Chairman, we are -- we think we've been very patient, but this is extremely friendly cross. It's putting in additional direct testimony, and the questions are not adverse to Mr. Herndon's position.

MS. CHRISTENSEN: May I be heard on this?

First of all, I'm trying to flesh out some discussion that was presented by their testimony -- their witness in cross-examination of this witness which he did not address in his testimony because it was only presented live here during the hearing. And I think that I'm not asking additional direct testimony. This is not beyond the scope of his testimony. He does talk about credit agencies, he did in the opening statement. So it's not beyond the scope and it's asking him to comment on testimony that was elicited here at the hearing for which he has not had an opportunity. And, moreover, our positions are not exactly aligned. I don't know that there's any legitimate objection.

CHAIRMAN CARTER: Tread lightly.

MS. CHRISTENSEN: I only have a few more questions.

CHAIRMAN CARTER: You may proceed.

MS. CHRISTENSEN: And if you grant me just a few more --

CHAIRMAN CARTER: You may proceed.

MS. CHRISTENSEN: Thank you.

BY MS. CHRISTENSEN:

Q Okay. Is S&P, Fitch and Moody's the only information you rely on as an institutional investor?

A No.

Q Okay. And do you know -- or let me ask you this. How much does whether an electric utility is a triple B rated company versus a single A company impact your decision on whether or not to make an investment in a company?

A The distinction between those two ratings is a data point that you should take into consideration, but in and of itself it's not that critical. It's another factor in the overall assessment, but in and of itself it's not that critical.

Q Okay. So that would not, in your opinion, deny Tampa Electric access to the capital markets or an institutional investor whether they're a single A or a triple B?

A I don't think that the existence of one rating or the other is going to weigh on whether they can access the capital markets. No.

MS. CHRISTENSEN: I have no further questions.

CHAIRMAN CARTER: Thank you.

Ms. Bradley.

MS. BRADLEY: Ms. Christensen covered them. Thank you.

CHAIRMAN CARTER: Thank you.

Mr. Wright.

MR. WRIGHT: Mr. Chairman, thank you. But Mr. Herndon is also my witness, so I don't have any, any questions for him on cross.

CHAIRMAN CARTER: Good deal.

Mr. Twomey.

MR. TWOMEY: No questions.

CHAIRMAN CARTER: Okay. Commissioners, I'm going to -- Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you.

Mr. Herndon, I've been trying to familiarize myself with CAPM models and the DCF, and I've said it here the last couple of days that it seems to me that those two models, as you said before, have some value, but they also have, I guess, some negatives to look at. And the negative I see is that they seem so subjective; that one could put the inputs in any direction they wanted to, have a particular outcome, and it could inflate or -- am I, am I correct in that assumption? Do you, do you see it as subjective? And, and then -- and I've asked this question too and I'll ask it again, if beta has no predictive value, how would that affect the CAPM outcome?

THE WITNESS: Let me try and answer your question this way, if I might, Commissioner.

Once you select the data that you wish to use in your formula, the formula functions mathematically in a fairly precise way. It produces a result, but it's a result that's driven very strongly by the information that you use, the currency of that information, the relevance of that information in the marketplace that you happen to be functioning in and so forth. So I don't wish to suggest that, that it's merely a subjective use of data that may or may not be precisely on point because it's not quite that simple.

But having said that, both models and all of the formulas for that matter that are available out there in the investing world can be interpreted a number of different ways. And I guess that's part of my concern here is that the Commission is being asked to consider these models and these formulas as if they were gospel, and they're just simply not. They're data points that you should take into consideration and you should give them the credence that they deserve, and that ultimately is in the eyes of each of you.

COMMISSIONER ARGENZIANO: Well, that's, that's interesting, very interesting. Because if you can do that -- and I found that in life that any time you have three or four ways to, to get somewhere, if, if you can, if the input or how you place the input or what you place into that could change the outcome drastically to one side or the other, personally I don't find that valuable. I like to get to something and say this is, this is how we get there and not manipulate it in any way.

So what I'm getting from that then is that all the methods are, are in my opinion questionable to get the outcome. I understand how they're used, but I still have a hard time understanding the inputs and how, how they get to that, to that outcome. With that said, let me go through some of your testimony. Just bear with me a second.

Let me ask you, investors today in this economic climate, in your opinion what do you think they would be looking for? And, you know, I'm looking at both sides of things, but I just put myself in that place and figure if I was the investor, what would I look for? And I'd like to know in your opinion what you think is a, I mean, a place where investors would want to go. How they would, you know, look at today's market and say, you know, I want to invest but I'm not going to invest here because I'm not sure, I'm going to invest here because I'm sure, or here because I'm taking a chance, and I guess they're taking a chance on everything.

But what, what do you think, I guess, of a utility stock, a Florida utility stock in today's market? Do you think it's a safe bet or a safer bet than most stocks out there? Is it a good place to invest?

THE WITNESS: Let me try and answer a couple of your questions, if I might, by saying that I think investors first and foremost in today's market want safety. They're willing to trade a little bit of return for sleeping at night.

Secondly, I think depending on your appetite for risk you can always take on more of a gamble if that's your preference. But if you look at the utilities that function in Florida, I think you can rest very comfortably on the basis that they are safe and secure. They're not going to pay perhaps quite the dividend or the appreciation as a high-flying company might, but they're also less risky and it allows you to sleep a little bit better at night, and I think that's what investors are looking for.

COMMISSIONER ARGENZIANO: You -- what method did you use in calculating the ROE?

THE WITNESS: Well, this was a question that was asked of me earlier. The truth of the matter is I don't have a canned formula for calculating an ROE. What I tried to do was to look at the presentations and the testimony of the witnesses that were put on by the company to weigh as carefully as I could the models that they used, the information that they were using to feed those models to look at my day-to-day experiences in the financial markets and reading and analyzing what is going on. Also to try and factor in the market conditions that we're all faced with in today's environment, including at the time the likelihood that some sort of fairly significant congressional bailout would pass and so on and so forth.

So all of those things went into ultimately concluding that a range of 7 to 8 percent would be acceptable to most investors, given the nature of the investment that they were making. If it was a, as I said, a much more high-flying company, then perhaps that would not be a sufficient return. But given that it's a secure, stable, long history, monopoly, noncompetitive company, that that was a reasonable return.

COMMISSIONER ARGENZIANO: And how significant should a risk be in factoring a company's, a utility's ROE, since you mentioned risk?

THE WITNESS: I'm not exactly sure how to answer. And when you say risk --

COMMISSIONER ARGENZIANO: Well, how do you factor in -- if I'm Company A who has far more risk, there's no guarantee of a revenue return, and then a company that has a guarantee of a revenue return, which one is, you know, which one weighs more in factoring in an ROE?

THE WITNESS: Any time you take on risk you should be compensated for it. The more risk you take on, the more you should be compensated for it. That's a very fundamental premise of investing.

In this case you have a company that although certainly exposed to risks such as hurricanes and so on and so forth is also, I don't wish to overstate this word, but it's also protected to a certain degree from those risks through a very solid regulatory environment, you know, a noncompetitive geographic territory, you know, Commission decisions that authorize pass-throughs for a number of factors that are in the overall base rate. So the company has a lower risk profile than many, many, many others and you would expect a lower return.

COMMISSIONER ARGENZIANO: In your testimony -- there's a couple of other questions I want to ask. In your testimony, I think in your direct the question was asked, some have suggested that allowing -- I know you spoke to this before, but I want to speak about it until I get a really good understanding. And they, the question was some have suggested that allowing Tampa Electric a 12 percent ROE may benefit ratepayers by lowering borrowing costs, and they asked do you agree. And I really want to understand that.

And your, part of your answer was any reduction in borrowing costs would likely be a slight incremental amount and would not offset the increased revenue requirements for ratepayers if a 12 ROE were to be authorized. And then you further say that customers would be worse off because they would be paying higher rates than necessary. Could you go over that again and tell me why you feel that way?

THE WITNESS: I guess the first thing I would, would say is that Tampa Electric at least in part is requesting an ROE of 12 percent in order to obtain a higher credit rating from the credit rating agencies. Their argument is that their triple B rating today is not sufficient to give them good access to capital and access to capital at a better rate, a lower cost.

I don't agree with their conclusion in the sense that, number one, I think they have reasonable access to capital. I think the company has shown that throughout its history. I think we're also aware that utility companies by and large were very successful in accessing capital throughout 2008; one of the most successful industries, if you will, of any of the industries in terms of accessing capital. So I don't accept that premise, number one.

Number two, if we accept the premise that they will get a higher rating, the cost to them that might result is only going to be marginally lower. It's not going to drop in a dramatic fashion. And as a consequence, I think what you're faced with is the reality that customers are going to pay a much higher rate for their electric service for several years until Tampa Electric comes back in for another rate case, at which point they're going to then adjust their rates to reflect that lower cost of borrowing that they got as a result of this rate case.

So what you have is a period of -- I heard one witness say they're going to be back in within five years. You know, I don't know.

COMMISSIONER ARGENZIANO: We don't know.

THE WITNESS: But let's say five years, maybe it's 16 like it was in this instance, that customers will pay a rate based on a 12 percent ROE. And in order to do that, they're going to -- the result of that is that they're going to get a marginally lower borrowing cost, maybe, you know, a half a percent or something on that order, maybe a little bit more depending on what they ultimately get.

So, you know, in my mind it's just not good economics to, to authorize that much of a, of a benefit on the front end in the anticipation of some undecided, unclear, unlikely outcome.

COMMISSIONER ARGENZIANO: So basically what you're saying is that the customers -- the benefit that the company will receive doesn't outweigh the cost to the customers. It's going to cost the customers a lot more to get a small little benefit for the company; is that right? I don't want to put words in --

THE WITNESS: Yes, ma'am.

COMMISSIONER ARGENZIANO: Okay. And you had mentioned that the southeastern states in rate cases I think indicating that they have been resolved or have been granted different ROEs. Could you elaborate on what you meant on the southeastern rate cases?

THE WITNESS: Well, I'm sorry, Commissioner. I was really responding to Commissioner Skop's question about the rate cases that were settled in the southeast. I'm not familiar with --

COMMISSIONER ARGENZIANO: Okay.

THE WITNESS: -- what they are. But I've always been a little reluctant to, you know, have a kind of follow the heard mentality here. I mean, the fact that Alabama may have settled a rate case is interesting and it's something that you should be aware of certainly. But does that mean that you should do it because Alabama did it? No, I don't think so. I mean, it's something you should take into consideration but that's all.

COMMISSIONER ARGENZIANO: Okay. I tend to agree with not going along with the herd mentality sometimes too. I think I've got a reputation for that: Sometimes right, sometimes wrong.

Also in your testimony and I think it was in Ms. Abbott's testimony also that Florida's regulatory environment is very, very, viewed very favorable. And as a matter of fact, as one of the -- ranked most favorably, I guess, is the ranking that the Florida regulatory scheme has. And could you tell me how that weighs in on the company, allowing the company to access capital?

THE WITNESS: Yes, ma'am. It in a, in a phrase reduces risk and makes the company a better investment with a lower expectation of return.

If you are in -- if you are an electric company in an environment where the Commission that regulates you is perverse and undisciplined and subject to all kinds of erratic decisions, that increases risk. But that's not the environment that Tampa Electric or any of the regulated utilities find themselves in in Florida. This is a very solid Commission with a long history of progressive regulation and that's reflected in their lower risks.

COMMISSIONER ARGENZIANO: Bear with me one minute, Mr. Chair. I think I have another question, if I could find the page. Well, while I'm finding it, I have thought of another question.

If the national average or the -- well, I guess it would be the national average is -- I don't know if I'm right. I think it was 10.5 percent. Does that sound right to anybody? The national average I think was, give or take, subject to correction, 10.5 percent. And if the company was granted a lower ROE as you suggest, 7.5, would that take them out of the competition, so to speak?

THE WITNESS: It would undoubtedly take them out of the competition in the eyes of some investors.

COMMISSIONER ARGENZIANO: Uh-huh.

THE WITNESS: But bear in mind that investors are, pardon me, looking to those higher returns because they have higher risk. So their risk appetite is perhaps a little bit more voracious than you or I might be.

I would be very comfortable with a rate of return of 7.5 or 8 percent given the low-risk nature of Tampa Electric and the utilities in Florida. Somebody else might want a higher return but they're willing to gamble.

COMMISSIONER ARGENZIANO: One second, Mr. Chair.

CHAIRMAN CARTER: No problem. Commissioner, if you want, I can go to staff and then come back to you.

COMMISSIONER ARGENZIANO: Yes. That would be great. Thank you.

CHAIRMAN CARTER: Why don't we do that.

Can we get -- hang on a second. Let me see. Do you need some water?

THE WITNESS: I've got some.

CHAIRMAN CARTER: Okay. Good.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Mr. Herndon, I just wanted to follow along to -- just one additional question that I did not get to before.

But going back to the -- again, different institutional investors have different goals. Some are looking for, you know, preservation of the investment and dividend growth and others are looking for aggressive growth and have more risk appetite.

But with respect to GE, I guess the, the investment, at least my recollection, that Berkshire Hathaway and Warren Buffet made in GE recently, I think it was in October 2008, was a $3 billion, $3 billion investment in preferred stock with a 10 percent dividend. And I think that I had asked if you knew what the credit rating of GE, which is a blue chip company, was, and you did not know. But subject to check, would you agree that for all practical purposes it's a triple A rating?

THE WITNESS: Certainly, Commissioner. Subject to check, I would agree with you.

COMMISSIONER SKOP: Okay. So I guess generally speaking, and I don't want this to be construed in any way, form or fashion that I'm in support of a higher ROE or anything like that, but I'm just trying to, to put out a scenario to illustrate today's capital markets. But if Berkshire Hathaway were making a capital or equity investment in a triple A rated company yielding a 10 percent return, would it not be reasonable to expect that if Berkshire Hathaway were making the same investment in a triple B rated company, that that return would be incrementally higher? I'm not saying how much higher, but some increment. Would you generally accept that premise?

THE WITNESS: I would generally accept that premise with the caveat that I would like very much to understand what was going on behind the scenes.

If I might, Commissioner, I don't recall the specifics of that particular investment, but I do recall that it was a, an arrangement that General Electric negotiated almost directly behind the scenes with Berkshire Hathaway. And my suspicion is that there was a great deal more there than met the eye. They went directly to Berkshire Hathaway, I suspect, because they needed help, and to get that help they had to pay for it.

COMMISSIONER SKOP: No. Absolutely. And, again, institutional investors have much more benefits available to them than the individual poor souls of investors that we are. You know, I wish I could make the deals that, or get the deals they get.

But, again, what I'm trying to illustrate is that, and this goes to Commissioner Argenziano's question, that there is some incremental difference in terms of the credit rating, and so I'm trying to kind of flesh that out. Because, again, the returns right now, the markets are in a state of flux and rate setting in today's economic environment is difficult at best. I mean, as you mentioned, the Commission has a rich history of and is well recognized nationally as being one of the best regulatory bodies in the state. But we also need to look out for our consumers, so that's factoring into the discussions and the full vetting that we're having.

With respect to one other point that you touched upon with the premise, and I think that Commissioner Argenziano touched upon this, about the notion that if a company has a higher credit rating, that essentially consumers would be paying more for that credit rating than they would gain by the lower borrowing costs. Would that necessarily be -- I mean, I tend to think that that has some merit to some degree, but would that necessarily hold true if a company were taking on a large capital project or a large capital undertaking to the extent that if you start to incur, if you started to incur large, a large amount of debt, at some point that lower borrowing cost -- and the reason I'm trying to put this into perspective is that some of the investments that this Commission approves are billions of dollars. And so when, when you look at millions or, you know, a fraction of a million versus the billion, I mean, kind of do the math, but a half a percent on a billion dollars, I think I could retire today. But I just wanted to get your perspective. At some point would there be, depending upon what happens in terms of capital projects, could there be a net benefit to the ratepayer?

For instance, if somebody were to, to -- you know, we have nuclear in Florida. I mean, half a percent on the borrowing costs on a nuclear reactor I think would probably more than outweigh -- you know, the, the borrowing costs, the savings and the borrowing costs would more than outweigh the additional incremental costs to the consumer. Would you, could you comment on that?

THE WITNESS: I think you're probably right that there's a, there's a flex point out there somewhere. I'm not sure exactly where it is. I think certainly the scale of the project or the scale of the investments is a factor.

I suspect the biggest issue though is the spread, you know, the spread between that increased or increasing credit rating, lowering of borrowing costs, whatever that spread is I expect is the real tipping point there. And I just don't think that in this case we're talking about a dramatic enough change. I think this is a marginal change here that we're talking about, and in that context I suspect it doesn't quite rise to that level. But I think you're right theoretically. Absolutely.

COMMISSIONER SKOP: Okay. Well, I appreciate your insight on this. Thank you so much.

COMMISSIONER ARGENZIANO: Mr. Chair.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: I think I've got it. I probably later will think of a whole bunch of other questions.

I went through your testimony, as I did other witnesses', and found some things that were very interesting to me, and I did a little bit more homework on them and derived some questions. But really I think what it comes down to for me and I guess what Commissioner Skop said basically on large capital projects that some of the companies are entering into, but I also have to look at legislation that's passed that basically says that on those large projects you pretty much can recover everything. And I go back to risk. And if you can recover everything, if I -- and correct me if I'm wrong because I'm kind of going to ask a question here -- I'm looking at investors and then I'm looking at those who loan the money to the companies. You want to keep the companies healthy, you want to keep them in the State of Florida, also want to make sure that the ratepayers don't suffer the consequences of bad decisions.

But if I'm an investor, I'm looking, and I want less risk because, Commissioner Skop had said before, you know, the return may be higher for some companies, but I also look and say the risk may be higher too. So in this kind of climate today I would think that a lot of investors are saying there's a lot of risk out there. I mean, GE is one that may be going out of business any day. But, so I'm looking for safety. I'm looking for less risk. Maybe the return is not quite as high, but the investor would look to a company or, or some type of investment that had less risk. And if, even if there are these big projects, if you have recovery clauses that say, even if you can recover down the line, isn't that still a safe, safer place for investors to go?

And on the second part of that question is those who loan the money, and I'm getting back to the A and the triple B because I'm starting to understand -- I think what you're saying is it's not that much of a difference between the two when it comes to acquiring the capital that you need from the, from the borrowers, I mean, from the loaners.

But from the perspective of those who loan the money, wouldn't those same features play or be part of the play and say, well, you know, I'm going to look at this company that's still investor, what do you call it, investor grade, is that the term, that's still investor grade and has a regulatory scheme that is the most favorable in the nation, don't they look at those factors too with the risk and say that, you know, who am I going to loan the money to, the GE, who may be going out of business today that has the higher return, or am I going to loan it to a company that has a guaranteed return that's not unhealthy and has less risk? And I know that's kind of a, sounds like a simple question, but does it work that way with those who loan the money?

THE WITNESS: Absolutely. Institutional investors and I suspect most personal investors want to have a certain amount of their portfolio, however large it might be, as kind of solid as bedrock. They want to be able to put it there, not have to worry about it, expect it to give them a fair return in the market that they happen to be in but not take undue risk. And so they build in that, that bedrock there. That's the part that anchors you to the wind in, in case future hurricanes come along. So, yes, you're absolutely right. I mean, lenders, whether it's, you know, Citibank or Bank of America or whoever it is, are constructing their portfolios with that thought in mind.

As far as the pass-through and recovery clauses and so forth are concerned, I couldn't agree with you more. And make that point that I think that's part of what gives in this case the company a, a sound regulatory environment is that the Commission has recognized that those pass-throughs are appropriate. And I realize that the company is not in the strictest sense 100 percent guaranteed every dollar that they spend, but the fact is that those recovery clauses do operate to essentially guarantee a recovery of almost all their costs and the disallowances are going to be on the margins in those cases. And, you know, I think that gives investors, whether it's individual or institutional investors, comfort.

COMMISSIONER ARGENZIANO: And I've been struggling with that because I don't want to put them out of competition.

THE WITNESS: Absolutely not.

COMMISSIONER ARGENZIANO: I don't want, I don't want the loan, those who would loan our utilities the money that they need, I don't want them to look and say, well, you know, I'd rather loan the company that has at least the national average, except, you know, this company may have a 7.5 below the national average, maybe, you know -- I don't know if they make that type of decision. I know an investor may make that kind of decision, say, well, you know, I'd rather go with a company that's on the national average at least in Florida rather than the one that's below, but I don't know if those who loan the money look at that also.

THE WITNESS: The lenders do it every single day. And, you know, in many respects I guess you could characterize the economic environment that we're in today as being a result of lenders forgetting to be more safety conscious. They started chasing, you know, higher returns, taking on more and more risk, and we are in the situation we're in as an overall economy because of that I think. And that's obviously simplistic, but --

COMMISSIONER ARGENZIANO: Getting back to the other question that I asked before, and I don't know if you have this and I don't know if the numbers have been -- when you say that the bang might not be worth it for the customer for the company to get the A rating when they can acquire capital today, is there a dollar figure, do we know a dollar figure of what it would cost the consumers for the company to get -- I'm trying to figure out what the bang is for the buck. Did you calculate that?

THE WITNESS: I did not calculate it. It could be done. What you have to do is calculate a series of different scenarios because there's no certainty about what the, how, what rate the money is going to be lent at and so on and so forth. So you'd have to construct a series of likely scenarios to give you some different outcomes and then work within that overall framework. And I, and I'm sure the staff could do that. It's not going to be an easy, out-of-the-envelope calculation.

COMMISSIONER ARGENZIANO: It would be -- the possibility is not --

THE WITNESS: But it's possible.

COMMISSIONER ARGENZIANO: Okay.

THE WITNESS: It would give you some food for thought. No question about that.

COMMISSIONER ARGENZIANO: Okay. If anybody has food for thought, I'd love to eat some.

But -- okay. And I guess the -- let me see. I think I, I think you've answered most of my questions. I probably have more, but I appreciate it. Thank you.

THE WITNESS: My pleasure.

CHAIRMAN CARTER: I'm going to come back in a minute, Commissioner. I'm going to go to Commissioner McMurrian. If you think of something, I'll come back to you.

Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you, Chairman.

And it's very nice to meet you, Commissioner Herndon. I've heard nothing but good things about you. And, of course, I haven't asked TECO after your testimony. But, anyway, we're glad you're here with us.

(Laughter.)

In your testimony on Page 17 you make a statement in there that you wouldn't quarrel with Witness Murry's formulaic approach in a normal investing environment and you bolded normal there. And I just wanted to be clear about understanding that.

If we were to accept your proposed ROE in this case of 7.5 percent and TECO were to come back in in, I don't know, a year, two, three years hopefully when the economy is better and we're back in that normal investment environment, would you support a formulaic approach in that case?

THE WITNESS: Commissioner, again, I think my answer would be that the formulas that Witness Murry uses and other witnesses have used are worthwhile inputs for you to take into consideration. The results that they produce in and of themselves should not be what drives your decision exclusively, and that's, that's where the rub is for me. It's not that -- I mean, I appreciate that there's some weaknesses in the formulas and so forth, but it's not the use of them as, as decision points for you. It's the exclusive use of them as decision points for you that troubles me very greatly.

And, and so three years from now if we're back at 14,000 in the Dow and everybody is just banging along and the best economy the world has ever seen and Tampa Electric comes in and says we need some adjustments, I think you ought to give them every consideration. Absolutely. I don't know what the result would be, but you certainly ought to listen to their arguments.

COMMISSIONER McMURRIAN: I appreciate that. And I realize in your testimony you've also taken issue that if you were going to use the mechanistic approach or the formulaic approach, that the inputs should be current and valid. You've said that.

But I'll just share with you, I mean, some of what I'm thinking is that while we have to consider the current state of the economy in making our decisions on several levels in the case, I guess from a regulatory certainty kind of standpoint I have some concern about using the formulaic approach or not depending on the state of the economy, I guess. And so I was trying to understand better, are you saying that, you know, you probably shouldn't use it here because of the state of the economy, but if the economy were better, we would use it? And I understand your point that you're not saying to rely on it exclusively, and I don't think that when we, when we do look at those formulaic approaches that we do, and there's probably a lot of subjective nature to it too as we've been talking about with the beta and the other risk premium inputs and that, and that they have a lot of, a lot of -- they definitely influence the outcome of using those different models.

But I guess I'll just let you respond to what I've said about that regulatory certainty and about using those formulaic approaches or not. And then just in general -- and then also have you proposed any inputs for those approaches, for using those mechanistic approaches, if we were to use those?

THE WITNESS: Here's the distinction that I think I would make, Commissioner, in terms of placing, as I've characterized it, undue reliance on these formulas.

I would agree with you that there's value in regulatory certainty and that the customers and the company and the creditors and everybody else in the, in the economic environment should have some comfort in that certainty.

We are in an extraordinary time. This is not, you know, 1998, this is not 1992, this is not 1985. This is 1929, you know, all over again, and it's that factor that really makes me even more cautious than I would normally be.

Otherwise, I would agree with you, I think, that, that you should rely on these formulas given valid inputs, given accurate interest rates and so on and so forth and give them credence -- not exclusive even in those circumstances, but give them credence.

But we're in a situation in an overall economic environment where a lot of the rules are not clear anymore and I think we're perhaps heading into a different kind of space than we've been in for a while. So it's the extraordinary nature that troubles me of our current environment.

COMMISSIONER McMURRIAN: And I guess one final follow-up. Did you propose any inputs for the, for these approaches, or even in the deposition, which I haven't reviewed yet, did you discuss, you know, where you found fault, I guess, with some of the inputs to those approaches?

THE WITNESS: The principal -- I don't want to mischaracterize this because we talked about this some in the deposition. I did not recommend to Witness Murry or to the company that they should use this dividend rate as opposed to another. My principal concern, and we did talk about this a little bit, was the interest rate environment that was driving many of these factors. Interest rates per se are not a factor in the formulas, in the precise application of the formulas, but they are the backdrop, as Witness Murry, I think, points out, they are the backdrop. They're -- one of the most important considerations that you can have in looking at any of these formulas is current interest rates, and his interest rate was just dated by virtue of when it was prepared. We now have an interest rate that's for all intents and purposes zero and that should be factored into the equation.

COMMISSIONER McMURRIAN: Okay. Thank you very much.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Sorry. I thought of some others.

First, I would like to ask because I'd like to get it into the record if we can get what I had asked prior about the bang for the buck, the sort of numbers or the possibilities that there would be for the company to -- as they say, if they went to an A rating, what that would cost the consumers. If we have, if we can have some possible scenarios, trying to figure out what the bang is for the buck, if we can enter that.

MS. BROWN: Could we consult just for a minute, Commissioner?

COMMISSIONER ARGENZIANO: Sure. And I'll ask the other, the other question, if I can.

CHAIRMAN CARTER: Commissioner, before you ask your next question, let me just, while staff is trying to get things together, just kind of a housekeeping matter.

COMMISSIONER ARGENZIANO: Sure.

CHAIRMAN CARTER: So that the Commission and the parties can plan. For planning purposes, today we'll probably take lunch between 11:30 and 12:45. So that gives us an opportunity -- and let's do this while staff is consulting.

COMMISSIONER ARGENZIANO: Sure.

CHAIRMAN CARTER: And we've been going at it for almost two hours with our court reporter. Let's give Linda a break and we'll come back on the half hour. We're on recess.

(Recess taken.)

We're back on the record and we have Mr. Herndon on the stand. And just before we left, we had asked -- and, staff, you're recognized to kind of explain where we are. And you're recognized, staff. Mr. Young.

MR. YOUNG: Yes. Thank you, sir. It's my understanding that TECO is going to, TECO wants to, TECO is going to provide the comparison, the comparisons. Also, FRF is going to provide an exhibit, the same exhibit. And I'll let Mr. Maurey speak to staff.

CHAIRMAN CARTER: Staff. Okay.

MR. MAUREY: Staff will file, prepare also an independent analysis.

CHAIRMAN CARTER: Okay. And that, Commissioners, will be 123. It'll be a composite exhibit. Let me ask staff, would it be better if I broke them up or what do you think?

MR. YOUNG: We can keep it as 123.

CHAIRMAN CARTER: Let's make it a composite exhibit.

So we'll have the, staff's analysis, the breakdown with the spread, the company's analysis and FRF's, do I have it right, and FIPUG's analysis and the OPC.

MS. CHRISTENSEN: Yeah. To the extent, I need to talk to my witness, but to the extent that we can do one, we'll provide it as well.

CHAIRMAN CARTER: Okay. That will be fine. So all the parties. And, Ms. Bradley, if you would like to do one, that would be fine as well. And that way we can, you know -- and a title, staff. Is it computation of the spread -- how about I just say computation of the spread between A and triple B? Everyone knows that we're trying to see what that cost ratio would be on that. That's as articulate as I can be on that for now, unless you guys want me to go further and I could be really loopier.

Mr. Wright.

MR. WRIGHT: Mr. Chairman, just so I'm clear, I would not suggest that you call this the bang for the buck exhibit, but I think it was my understanding that that's what we were talking about.

CHAIRMAN CARTER: That is correct. It is the bang for the buck exhibit.

MR. WRIGHT: It would be an appropriate analysis of the difference in costs to customers of achieving a higher, a higher debt rating and ostensibly a lower debt cost in return for paying a higher return on equity. Is that a correct understanding?

COMMISSIONER ARGENZIANO: Isn't that so much more complicated than bang for the buck?

CHAIRMAN CARTER: Bang for the buck.

MR. WRIGHT: Of course it is.

CHAIRMAN CARTER: It's a short title. I was looking for a short title, you know.

MS. CHRISTENSEN: Commissioners, can I ask for some clarification?

CHAIRMAN CARTER: Hang on one second. Hang on. Let's work on the title here.

MS. CHRISTENSEN: Bang for the buck.

MR. WRIGHT: How about Debt/Equity Cost Comparison.

CHAIRMAN CARTER: Debt/Equity Cost Comparison. Does anybody have any heartburn on that? I'm really liking bang for the buck, but we'll go with Debt/Equity Cost Comparison. Debt/Equity Cost Comparison.

Ms. Christensen.

MS. CHRISTENSEN: I was just wondering if we had some clarification over a particular time period and what ROE spread you wanted to use between the 12 and the 10 just to make it uniform or --

CHAIRMAN CARTER: I think what we probably ought to do, Commissioners and staff, I'm thinking aloud and sometimes that's not necessarily the best thing to do, use the same timeframe that the company used, that we're using in this, in the case. Wouldn't that make sense, if you guys used the same -- yeah. It would --

COMMISSIONER ARGENZIANO: Is there such a thing as as soon as possible?

MS. CHRISTENSEN: Like a five-year time spread or something like that?

COMMISSIONER ARGENZIANO: Yeah. And I think that --

CHAIRMAN CARTER: Mr. Wright, you're shaking your head. What are you --

MR. WRIGHT: I'm just trying to get my arms around, around the scope. I mean, we're talking about a 2009 test year. I think maybe 2009, 2010 would be a good period, 2009, '10, '11.

CHAIRMAN CARTER: Mr. Willis?

MR. WILLIS: I believe that it is, would be inappropriate at this juncture for us to set a specific timeframe or any of these detailed parameters. I think it's important for us all to do an analysis and to set out exactly what we've done and to, to present an analysis of what the Commission wants. I think we've all heard the, the testimony and the responses here and can address that. I think it becomes too confining to, to, to try here on the fly to specify this too closely.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Well, if it comes in too late, it's useless. So if the company can't provide it in a certain amount of time, maybe they can't, maybe the others can.

MR. WILLIS: No. The time, I'm not speaking about that time. We can provide it quickly.

COMMISSIONER ARGENZIANO: Oh, you mean the time of the years.

MR. WILLIS: All these different parameters, how do you make this analysis?

CHAIRMAN CARTER: Well, I thought what I said was the simplest thing in the fact that we're talking about a finite time in the rate case here, the years that we use there. That's what I thought would make sense to everyone, you know. Where is that chart that tells us? Andrew, have you got -- can you -- do you have a suggestion on, a simple one?

MR. MAUREY: No, but I'll come up with something.

MR. WRIGHT: Mr. Chairman?

CHAIRMAN CARTER: Mr. Wright.

MR. WRIGHT: I'll just add, we have no heartburn with, with Tampa Electric's suggestion, which I think a former member of this, a couple of former members of this Commission would refer to as the get your best hold on the exhibit approach. It may be more, it may be more voluminous than you want. But I think, you know, the company's witness --

CHAIRMAN CARTER: We should have gone with the bang for the buck. Do you see that?

MR. WRIGHT: The company's witness will have an idea of what they believe is the appropriate time period. Our witness will have the same. Dr. Woolridge will have the same. We're happy with that.

CHAIRMAN CARTER: Okay. That's fine. Ms. Christensen, does that help?

MS. CHRISTENSEN: As long as I guess it's clear on the exhibit what timeframe you used and the differential between the ROEs that are used.

CHAIRMAN CARTER: Yeah. That will be in your, that will be in your own exhibit and we can evaluate.

MS. CHRISTENSEN: As long as it's clear I think on everybody's exhibit so you can attempt to make some sort of comparison yourselves, then I think we can probably live with that parameter.

CHAIRMAN CARTER: Okay. And that will be a late-filed exhibit. And thank you so kindly on that.

(Late-Filed Exhibit 123 identified for the record.)

Commissioner Argenziano, you're recognized.

COMMISSIONER ARGENZIANO: I just have I think two other questions for Mr. Herndon.

Do utility stocks --

CHAIRMAN CARTER: 123. Wait.

COMMISSIONER ARGENZIANO: Sorry.

CHAIRMAN CARTER: I'm at 123.

MR. YOUNG: It's 123.

CHAIRMAN CARTER: 123? Okay.

You may proceed.

COMMISSIONER ARGENZIANO: Do utility stocks normally, I don't know whether the word is do better in the investment markets, and how would they be doing in your opinion now in the type of market that we have now? Do you know?

THE WITNESS: The, the utility stocks as a group have performed better than the Dow Jones industrial average, than the S&P 500 or the NASDAQ over the last couple of years.

Now when I say perform better, that's a very relative term. What I mean by that, in this specific time period we're talking about, the last couple of years, is they've lost less money than the other indices. Obviously each individual company may or may not be performing better or worse and that's a function of so many variables.

COMMISSIONER ARGENZIANO: But in mass --

THE WITNESS: But when you put them all together and you look at the utilities versus the industrials versus the S&P 500 versus NASDAQ stocks, utility stocks have performed better. And, again, as I say, that means they have lost less. That's not the outcome that you want, but nevertheless that is better performance.

COMMISSIONER ARGENZIANO: And the second part of that question, do you think, I have my own opinion but I'm not an expert and I'm trying to formulate one, do you think that they have performed better because of the characteristics, the, the less risk, the certainty of cost recovery, the certainty in the revenue stream? Is that, is that one or all of the components that makes them perform better?

THE WITNESS: Without a doubt. In an environment like we're going through right now, investors flee to quality and they flee to safety. That's what they want more than anything else. And they know full well that they're not going to get paid as well with a utility stock as they might with a high-flying company, but their money is going to be safe and they're going to get a reasonable return and that's what they want. They want security and safety and that's what they get with utility stocks by and large.

COMMISSIONER ARGENZIANO: Thank you. Thank you, Mr. Chair.

CHAIRMAN CARTER: Thank you. I'm going to go to staff now, Commissioners, but always I can come back to the bench.

Staff, you're recognized.

MR. YOUNG: We have no questions.

CHAIRMAN CARTER: Okay. Anything further from the bench?

Okay. Redirect?

MR. WRIGHT: Yes, sir.

CHAIRMAN CARTER: One second. Give you guys a chance to get --

MR. MOYLE: Can we talk?

CHAIRMAN CARTER: Yes, sir. You've got a minute. Take a minute.

Just while they're doing that, Commissioner Skop, for the record we marked it as a composite Exhibit 123, and that's the bang for the buck -- actually we called it the Debt/Equity Cost Comparison, and it will be a late-filed and each one of the parties will present this Debt/Equity Cost Comparison about the ratio, and both staff will present one and each one of the parties will present that. And so 123 will be a composite exhibit of that. I'm trying to get my notes together here.

Okay. Mr. Moyle, you're recognized for your redirect.

MR. MOYLE: Thank you, Mr. Chairman. And as indicated when Mr. Herndon took the stand, he's sponsored by the Florida Retail Federation and FIPUG. So Mr. Wright and I compared notes briefly, but I'm going to go ahead and conduct the redirect on a couple of points.

CHAIRMAN CARTER: Okay.

REDIRECT EXAMINATION

BY MR. MOYLE:

Q Mr. Herndon, in response to a question from Commissioner Skop talking about the signal to Wall Street, I think he used the phrase "extreme measure." You're not, you're not suggesting that your recommendation is an extreme measure, are you?

A No, I'm not.

Q Okay. With respect to a question about other rates decided in the southeastern United States, the debt market is a national market; correct?

A Yes.

Q And I think while you said that those cases would, you know, be another data point that could be considered, with respect to accessing debt it may be more appropriate to consider nationally the cases decided around the country and the respective ROEs if you were going to use that as a, as a tool for informing your decision.

A I think any time you can get a larger sample population you're better off using that, and so I would certainly agree with you.

Q Okay. There were some questions about GE and the Berkshire deal that was done. Preferred stock is not the same as bonds; correct?

A Correct.

Q Okay. And then finally, Commissioner Argenziano asked you some questions about, and so did Commissioner Skop about the relative measurement of impacts as related to having lower cost of debt as compared to a higher ROE. If I could just spend a couple of minutes and discuss that, that with you. Your high end of your recommendation is 8 percent, correct --

A Yes.

Q -- in terms of ROE? And Commissioner -- I'm sorry. Dr. Murry's recommendation is 12 percent. Have you assumed, and I think this is in the record, that each percentage point in the ROE was $30 million, that would be a $120 million spread on ROE, correct, the difference between 8 and 12 percent?

A Correct.

Q And that would be something that ratepayers would see this summer upon the conclusion of the hearing if, if a 12 percent return were, were awarded; correct?

A The rates to capture that amount would start and would continue monthly, yes.

Q Okay. There's been some testimony and some evidence about the spread in the debt markets between triple B and A. And for the purposes of the question I'd ask you to assume that it's a 2 percent spread.

A Okay.

Q And I'd also ask you to assume that Tampa Electric is going to go into the debt markets for $250 million. And to make it simple, let's just say they're going to do it, you know, next November, $250 million. A 2 percent spread on

$250 million is $5 million; correct?

A Correct.

Q In terms of the debt difference? And that would be $5 million per year that you would have in lower debt costs; correct?

A Correct.

Q There were questions about how long you would have to run these numbers to make a judgment about where do you get your bigger bang for your buck. But if you, if you did them for five years, five, $5 million savings over five years is $25 million; correct?

A Correct.

Q And if you did --

MR. HART: Mr. Chairman, I hate to interrupt, but this is the most inappropriate direct testimony. Mr. Moyle is just testifying and asking the witness if he's correct. These aren't questions. These are leading questions and they're extremely leading questions and we would object to them.

CHAIRMAN CARTER: He's right, Mr. Moyle. I've given you great leeway, so let's wrap it up.

MR. MOYLE: Okay. I think I have one or two more questions. That'll be it.

CHAIRMAN CARTER: Okay. Let's do it. I'm going to withhold my ruling. Just wrap it up.

MR. MOYLE: Thanks.

BY MR. MOYLE:

Q $120 million times five is $600 million?

A Correct.

Q Would those be the two numbers that you would consider, the $5 million times five years, if you used a five-year time frame, $25 million as compared to $600 million for trying to figure out, you know, the bang for the buck in your opinion?

A I haven't had a chance to think through the numbers or the various factors associated with the calculation that you're describing. On the surface that seems to be correct. I'd like the opportunity to verify that, but on the surface that seems to be correct.

MR. MOYLE: Okay. That's all I have, Mr. Chairman. Thank you.

CHAIRMAN CARTER: Thank you. Thank you. Exhibits? Number 54, are there any objections?

MR. HART: No, Mr. Chairman.

CHAIRMAN CARTER: Okay. Show it done without objection.

(Exhibit 54 admitted into the record.)

Also, Commissioners, the Exhibit Number 123 is a late-filed, so that's the composite exhibit we'll be looking for.

Commissioners, anything further for this witness?

MR. HART: Mr. Chairman, was Exhibit 122 entered into the record?

CHAIRMAN CARTER: Yes, it was. Yes, it was.

MR. HART: Thank you.

CHAIRMAN CARTER: Thank you for the reminder. But Exhibit 122, as you know, Commissioners, that was Mr. Herndon's deposition. It was entered into the record without objection.

So thank you, Mr. Herndon. You may be excused.

THE WITNESS: Mr. Chairman, thank you. Might I just add it's a lot more fun up there than it is down here?

CHAIRMAN CARTER: Sometimes it is.

Okay. Is it Mr. -- Mr. Moyle.

MR. MOYLE: Mr. Pollock is the next witness.

CHAIRMAN CARTER: He's been sworn.

MR. MOYLE: And Ms. Kaufman is going to handle that witness.

CHAIRMAN CARTER: Oh, Ms. Kaufman. Okay. Let's take a moment.

Before you get going, let's just take about a five-minute stretch break, Commissioners. We'll start on the hour.

(Recess taken.)

We are back on the record. And when we last left, I think, Ms. Kaufman, you're up. You're recognized.

MS. KAUFMAN: Thank you, Mr. Chairman.

The Florida Industrial Power Users Group has called Mr. Jeffry Pollock. And Mr. Moyle is going to be passing out an errata to Mr. Pollock's testimony that was provided to all the parties Monday of this week.

CHAIRMAN CARTER: Excellent. You may do so. Let's do -- let Mr. Moyle pass this out and then we'll begin the, let Mr. Pollock do his opening at that point in time. Okay. Let's hang on for a second.

MS. KAUFMAN: And I would just ask, if it's all right while we're waiting, I think I'd like to give this an exhibit number, if that would be all right.

COMMISSIONER EDGAR: Of course.

MS. KAUFMAN: Because it contains some revised exhibits as well. Just so the record is clear.

CHAIRMAN CARTER: No problemo. Let's make this one Exhibit 125. Wait. Hang on. Let me be sure here before I -- 124.

MS. KAUFMAN: Thank you, Mr. Chairman.

CHAIRMAN CARTER: This will be Exhibit 124. How about a title?

MS. KAUFMAN: I think we can just call it Pollock Errata Sheet.

CHAIRMAN CARTER: I love it. See, simple.

MS. KAUFMAN: I'm trying.

CHAIRMAN CARTER: There you go. I like it.

(Exhibit 124 marked for identification.)

Does everyone have a copy? Okay. You may proceed.

MS. KAUFMAN: Thank you, Mr. Chairman.

JEFFRY POLLOCK

was called as a witness on behalf of the Florida Industrial Power Users Group and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. KAUFMAN:

Q Mr. Pollock, would you state your name and business address for the record, please.

A Yes. I'm Jeffry Pollock. My address is 12655 Olive Boulevard, St. Louis, Missouri.

Q By whom are you employed and in what capacity?

A I'm employed at J. Pollock, Incorporated, and I am its President.

Q Mr. Pollock, you are testifying on behalf of the Florida Industrial Power Users Group; correct?

A Yes.

Q Did you cause to be filed in this proceeding 87 pages of direct testimony?

A Yes.

Q And we have distributed an errata sheet which has some changes to your direct testimony; correct?

A Yes.

Q With these changes, if I asked you the questions in your direct testimony this morning, would your answers be the same?

A Yes, they would.

MS. KAUFMAN: And, Mr. Chairman, we would ask that Mr. Pollock's testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of the witness will be entered into the record as though read.

BY MS. KAUFMAN:

Q Mr. Pollock, did you also have 19 exhibits to your testimony that I believe have been marked as Exhibits 55 through 73?

A Yes.

Q And also we have passed out an errata to three of those exhibits; is that correct?

A Yes.

Q And with those changes, are your exhibits accurate and correct as you sit here today?

A Yes.

(Exhibits 55 through 73 marked for identification.)

1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

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 WHO 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. More details are provided in Appendix A 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) and The Mosaic Company (Mosaic).[1]

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

A I am testifying on TECO's proposed revenue requirements, retail class cost-of-service study, class revenue allocation, firm and non-firm rate design, and the Transmission Base Rate Adjustment (TBRA).

Q **ARE YOU SPONSORING ANY EXHIBITS?**

A Yes. I am sponsoring **Exhibits ___(JP-1)** through **___(JP-19)**. Many of these exhibits are based on TECO's claimed revenue requirements in this proceeding.

As such, they are for illustrative purposes only and should not be interpreted as an endorsement of TECO's proposed base rate increase.

Summary

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A My recommendations are as follows:

- Reductions of $17.5 million to TECO's claim base rate revenue increase, which remove, abnormally high expenses for plant outages, to provide for a five-year amortization of actually incurred (rather than projected) rate case expenses, and exclude incentive compensation tied to achieving certain financial goals because it benefits shareholders and not TECO ratepayers;
- Revisions to TECO's class cost-of-service study that maintains the current homogeneous (GSLD and IS) customer classes, more appropriately classifies the Big Bend scrubber and Polk gasifier costs to demand, rejects the 12CP-25% AD method (which has never been approved by this Commission), applies the Commission-approved 12CP-1/13th AD method of allocation, and treats interruptible customers as firm for both pricing and costing purposes;
- A revised class revenue allocation that follows the revised class cost-of-service study and moves all rates to cost (*i.e.*, parity) while moving the lighting facilities class closer to cost;
- A firm rate design where demand and energy-related costs are recovered in demand and energy charges, respectively, and appropriate credits are provided to customers taking service at higher voltages;

- An interruptible rate design that will provide greater stability, more properly reflect the value of interruptibility, which is a cost that should be borne by firm customers, and fairly compensate interruptible customers; and
- Rejection of fifth piecemeal cost recovery clause, the Transmission Base Rate Adjustment factor, which is not needed, would unnecessarily shift risk to ratepayers and allow TECO to over-recover certain transmission rate base additions.

2. REVENUE REQUIREMENTS

Q **WHAT REVENUE REQUIREMENT ISSUES ARE YOU ADDRESSING?**

A I am addressing TECO's proposed test year production operation and maintenance (O&M) expenses related to scheduled outages, rate case expenses, and incentive compensation.

Q **DOES THE FACT THAT YOU DO NOT DISCUSS ALL OF TECO'S REVENUE REQUESTS MEAN THAT YOU ENDORSE THE OTHER REQUESTS TECO HAS MADE?**

A No. Based on the volume of material filed, as well as time constraints, I will only comment on selected revenue issues. I am sure that other parties will discuss additional revenue issues. The fact that I do not discuss such issues in my testimony does not mean that FIPUG and Mosaic endorse or support the other revenue requests TECO has made.

Q **WHAT IS THE TEST YEAR THAT TECO PROPOSES TO USE FOR PURPOSES OF SETTING RATES?**

A TECO is proposing to use a forecasted test year, using projected sales, revenues and expenses for 2009. In doing so TECO is apparently seeking to match rates to the time frame when those rates will be in effect.

Q **EXPLAIN THE CONCEPT OF THE TEST YEAR.**

A A test year is a period of time used to measure the utility's revenues and expenses for the purpose of setting base rates. In order to set rates that provide the utility a reasonable opportunity to earn a reasonable return on its used and useful investments, a test year must be representative; that is, the revenue requirements (which consist of a return on rate base plus operating expenses) should be set using sales, revenues, expenses and net investments that reflect the conditions expected to exist during the period when new base rates are in effect. Thus, non-recurring and other atypical costs should be removed.

Q **IS TECO PROJECTING A CONTINUATION OF THE GROWTH IN SALES THAT HAS OCCURRED IN THE MOST RECENT 10-YEAR PERIOD?**

A No. In the short run, 2008 and 2009, TECO is projecting sales increases. However, the increase in test year sales is below the TECO's projected average 2008-2017 sales growth.[2] Specifically, projected growth in total sales for 2008 is approximately 0.8% and for 2009 growth is approximately 1.5% -- both below the projected 2% average used for the remainder of the time period.

Q **DOES THE SLOWER PROJECTED GROWTH RAISE ANY CONCERNS?**

A Yes. Base rates reflect a utility's test year costs divided by test year sales. The higher the costs (*i.e.*, the numerator) and/or the lower the sales (*i.e.*, the denominator), the higher the rate. All things being equal, the higher rate will provide the utility the opportunity to cover increased costs and provide increased returns to shareholders. Given that TECO is forecasting a slower growth in sales – particularly in the Test Year – and higher O&M expenses, the Commission should thoroughly "scrub" the filing and remove unnecessary and unreasonable costs.

Q. **WHAT GROWTH RATE HAS TECO USED TO DETERMINE WHAT GENERATION AND PLANT IT NEEDS?**

A TECO has procured generation capacity and added plant in service in anticipation of continued 2% per year sales growth. This includes the addition of five new combustion turbine (CT) units in the test year, totaling 285 MW. With slower sales growth, the proposed base rates will be higher. All other things being equal, the resumption of normal sales growth would result in lower per unit costs. This would allow TECO to absorb higher base rate costs, such as additional transmission investment, without the need for additional rate relief, as discussed later in this testimony.

Scheduled Outages

Q HAVE YOU REVIEWED THE O&M EXPENSES FOR SCHEDULED PRODUCTION PLANT OUTAGES?

A Yes. As part of my review of TECO's projected test year O&M expenses, I have determined that these expenses are overstated because they reflect an abnormal number of scheduled (or planned) outages. Thus, I recommend that test year O&M expenses be adjusted to reflect a more normal level of scheduled outages.

Q WHAT DID YOUR REVIEW OF PLANT OUTAGES REVEAL?

A TECO is projecting the highest number of scheduled outages in 2009 than in any other year since 2003. TECO's projections are provided in **Exhibit __(JP-1)**. Specifically, the planned outages at Big Bend Station are shown on page 1, while total planned outages are shown on page 2. As can be seen on page 1, TECO projects the duration of planned Big Bend outages to increase from 22.5 weeks in 2008 to 32 weeks in 2009, a more 30% increase. Overall plant outages would increase from 43 weeks in 2008 to 54 weeks in 2009 (page 2).

Q WOULD YOU CHARACTERIZE THE TEST YEAR OUTAGES AS NON-RECURRING?

A Yes. The last time two major Big Bend outages occurred in the same year was in 2006 when Units 1 and 3 were both down for major inspection outages.[3] In 2009, there are three outages. Two of the three 2009 scheduled outages are to install selective catalytic refiners (SCR) at Units 1 and 2.[4] TECO has also scheduled a maintenance overhaul of most of the operating equipment and boiler of Unit 4.[5] Further, the SCR-related outages are non-recurring. As TECO witness, Mr. Hornick, points out, the Company's settlement with the

Environmental Protection Agency and the Florida Department of Environmental Protection require that these alterations be in place by 2010[6].

Q DID TECO ORIGNALLY PLAN FOR TWO MAJOR BIG BEND OUTAGES IN 2009?

A No. **Exhibit ___(JP-2)** is a document provided in discovery that shows the planned outages for Big Bend for the period 2007-2013. The document shows that the Company originally planned only one major outage per year at Big Bend through 2013.

Q IS THERE ANY RELATIONSHIP BETWEEN THE NUMBER OF PLANNED OUTAGES AND THE COSTS ASSOCIATED WITH THESE OUTAGES?

A Yes. **Exhibit __(JP-3)** shows the outage costs for the period 2003-2009. As can be seen, TECO incurs higher costs in those years when more outages occur. This is particularly evident when comparing the test year to prior years. For example, in 2008, there were 43 outage weeks that resulted in $13.7 million of O&M expenses. This compares to 54 outage weeks at a projected cost of $20.2 million for the test year. The projected increase can be attributed to Big Bend.

Q SHOULD AN ADJUSTMENT BE MADE TO TEST YEAR O&M EXPENSE?

A Yes. The test year should be representative of normal circumstances. Using past history and TECO's planning document as a guide, it is simply not normal to have multiple major outages at the Big Bend Plant. For that reason, I recommend that Test Year O&M expenses be adjusted to reflect normal maintenance outage levels in terms of costs.

The recommended adjustment is quantified in **Exhibit __ (JP-3)**. Specifically, TECO has incurred or budgeted for an average of $12.2 million per year in outage-related expenses over the period 2003 – 2009. Thus, TECO should be allowed $12.2 million for planned outages during the test year and

TECO's proposed expense should be reduced by $8 million.

Rate Case Expenses

Q HOW DOES TECO PROPOSE TO RECOVER RATE CASE EXPENSE?

A TECO proposes to recover $3.15 million in rate case expenses amortized over three years.

Q DO YOU HAVE ANY RECOMMENDATIONS WITH REGARD TO TECO'S PROPOSED RECOVERY OF RATE CASE EXPENSE?

A Yes. I have two recommendations. First, rather than including a projection of what the expense will be, upon completion of the proceeding, and as part of the compliance filing, TECO should be required to provide actual rate case expenditures, with the actual expenditures being used to set the level of rate case expense to be recovered from customers. Second, the amortization period for rate case expenses should be at least five years rather than the three years TECO requests.

Q WHY DO YOU RECOMMEND A LONGER AMORTIZATION PERIOD FOR RATE CASE EXPENSE?

A TECO's last rate case was in 1992. There is no indication when TECO will file its next case following this case. Since 1992 TECO has begun to use cost recovery clauses to recover carrying costs for items that would normally fall in base rates. The most significant is the costs related to environmental capital expenditures. As discussed later, TECO is proposing to shift $22 million from base rates to the conservation clause by terminating Schedules IS and SBI. If history is any guide, there will be an extended period of time between this rate case and TECO's next rate case. A longer amortization period is much more in line with TECO's rate case history. Adjusting the amortization period from three to five years would reduce TECO's revenue requirement by $420,000.

Incentive Compensation

Q HAVE YOU REVIEWED THE TEST YEAR EXPENSES FOR INCENTIVE COMPENSATION?

A Yes.

Q. ARE THERE PORTIONS OF THE REQUEST THAT RAISE AN ISSUE?

A Yes. A portion of TECO's total compensation is tied directly to the financial performance of the operating company and the parent company. The issue is whether compensation tied to financial performance should be included as an expense for ratemaking purposes.

Q SHOULD INCENTIVE COMPENSATION THAT IS TIED TO FINANCIAL PERFORMANCE BE ALLOWED IN RATES?

A No. Incentive compensation that is contingent upon the parent and/or operating company achieving certain financial goals, such as net income, cash flow, or other (stand-alone or comparative) measures, is beneficial to shareholders but not of direct benefit to ratepayers. For this reason, incentives to achieve financial goals are appropriately borne by shareholders not ratepayers.

Q WHAT FINANCIALLY-BASED PERFORMANCE INCENTIVES ARE REFLECTED IN TECO'S TEST YEAR EXPENSES?

A TECO witness Merrill describes two components of TECO's annual pay program. First, there is an annual merit increase which is predicated upon individual performance and overall salary position relative to the market.[7] The second component of the annual pay program is the "variable incentive pay program known as 'Success Sharing'. It provides an annual one-time payment based on the achievements of the team member and company against pre-established goals".[8] TECO has included the expected payouts under the Success Sharing Plan in the gross payroll reflected on Schedule C-31. Incentive compensation is not separately broken down in the filing or the Company's Testimony.

Q **WHAT IS YOUR UNDERSTANDING OF THE SUCCESS SHARING PLAN?**

A There are three levels of participation – Officers, Key Employees and General Employees. Under the Officer Short Term Incentive portion of the plan, goals are established at the corporate, operating and individual levels and payout is based on level of achievement. However, "the payout to all participants is zero if TECO Energy's income threshold set for that year by the Compensation Committee is not achieved." [9]

The Key Employee Short-Term Annual Incentive Plan is administered "virtually identical to the incentive plan for officers" with goals based 50% on financial and 50% on individual.

The general employee short term incentive program is available to all non-officer/key employees and is based upon five non-financial goals and two financial goals, cash flow and net income. The maximum payout under the plan is 12% of either the higher of the employee's total earnings or the job market value for the calendar year.[10]

Finally, there is a separate officer/key employee long-term incentive program which awards shares to employees. There are two classes of awards, performance restricted shares, for which total shareholder return must exceed the bottom quartile of a group of peer companies for there to be any award, and a time-restricted award, for which the officer/key employee must remain with the company for a given period of time.

Q **HAS TECO PAID ITS EXECUTIVES AND OTHER EMPLOYEES INCENTIVE COMPENSATION IN THE PAST?**

A Yes. **Exhibit ___(JP-4)** is a copy of TECO's Response to OPC's Third Set of Interrogatories No. 29. It shows that TECO has paid Incentive Compensation in each year since 2003. In all but 2003, employees received payments in excess of the targeted level of incentive compensation. The most recent actual payment made was for 2007, in which employees received $12.9 million in incentive compensation.

Q **HAVE YOU BEEN ABLE TO DETERMINE WHAT INCENTIVE COMPENSATION WAS RECEIVED BY ANY OF THE OFFICERS OF TECO DURING 2007?**

A No. However, published information reveals that two TECO officers, the President and CFO, received approximately $1.5 million in incentive compensation including stock awards worth approximately $810,000 and non-equity incentive payments of approximately $690,000 for 2007[11].

Q **WHAT IS TECO'S JUSTIFICATION FOR SEEKING RECOVERY OF 100% OF THE INCENTIVE COMPENSATION FROM RATEPAYERS?**

A According to TECO witness Merrill, the purpose of the Success Sharing Plan is "to attract, retain and motivate high performing goal-oriented team members." However, as explained above, the portion of the compensation to executives and key employees is predicated upon the corporate parent, TECO Energy attaining certain financial goals. Further, even the general plan for all non-executive/key employees rewards the individuals predicated upon financial goals of not only the operating company (TECO) but also is upon certain financial goals for the parent company, TECO Energy.[12] In current economic times, when executive compensation has come under great scrutiny and criticism, this Commission must ensure that all compensation is directly related to enhancing the value ratepayers receive and is not a windfall for executives.

Q HAVE OTHER JURISDICTIONS DISALLOWED INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?

A Yes. Texas, a jurisdiction in which I have testified with regularity, has disallowed the portion of incentive compensation tied to corporate financial objectives.[13] Specifically, in the AEP Texas Central rate case, the Public Utility Commission of Texas (PUCT) permitted inclusion of the incentive compensation only to the extent that it was tied to operational factors.

The Proposal for Decision (PFD) addressed the issue initially, pointing out that the incentive compensation was predicated on both financial and operational objectives.[14] In addressing the issue of inclusion in rates, the PFD addressed the issue as follows:

> With regard to the measures themselves, the Financial Measures are of more immediate benefit to shareholders and less so to ratepayers. Conversely, the Operating Measures are of more immediate benefit to ratepayers and less so to shareholders. The question is whether these various interests satisfy the regulatory scheme by which expenses may be included as part of a proposed rate change. By statute, the Commission may not consider for ratemaking purposes an "expenditure, including an executive salary, . . . [that the Commission] finds to be unreasonable, unnecessary, or not in the public interest." By rule, the Commission has interpreted the "public interest" requirement to mean that an expense is "reasonable and necessary *to provide service to the public.*"[15]

The PFD went on to conclude that the operational goals and related incentive compensation were reasonable and necessary expenses in the setting of rates:

> The Applicant makes a plausible case for including in the cost of service the 34% portion of the incentive expense that is related to Operational Measures. By their very nature, Operational Measures reflect goals that relate to the public interest. Indeed, many are required to be considered as independent issues in this proceeding. Although the Operational Measures relate to AEP as a corporate holding company rather than to the Applicant, the Applicant shares in those Operational Measures on an allocated basis. The ALJs find that the goals of the Operational Measures are in the public interest and reasonable and necessary to provide service to the public.[16]

In reviewing the PFD and issuing its own decision, the PUCT concluded as follows:

> The financial measures are of more immediate benefit to shareholders, and the operating measures are of more immediate benefit to ratepayers.
>
> Incentives to achieve operational measures are necessary and reasonable to provide T&D utility services, but those to achieve financial measures are not.[17]

The Commission approved recovery of 34% of $4.4 million in requested incentive compensation, with $2.8 million being disallowed.[18]

Likewise, the Wyoming Public Service Commission disallowed 50% of PacificCorp's proposed incentive compensation because business unit and corporate incentives are primarily for the benefit of shareholders.[19] The Wyoming Commission found:

> Part of PacifiCorp's employee compensation package is made up of incentives for meeting various goals set at different levels of organization on the individual (50%), business unit (30%) and corporate (20%) levels. PacifiCorp recommended that 5% of the overall incentive package should be considered related to shareholder rather than rate payer benefit and therefore excluded for rate making purposes. . . . WIEC recommended that half of the incentive compensation package should be excluded. . . . The exclusions are based on the premise that the business unit and corporate incentives, which total 50%, are primarily of benefit to shareholders rather than rate payers. WIEC observed that, "[b]y tying incentive payments to financial performance, PacifiCorp made the financial success and enhanced shareholder wealth significant objectives for [its incentive plan]." . . .
>
> We adopt the WIEC adjustment as a fair and reasonable sharing of the value of the incentive program between the rate payers and PacifiCorp's shareholders. This tracks the most prominent divisions of the plan and fairly allows for the situations in which program elements might benefit both shareholders and ratepayers.[20]

Q SPECIFICALLY WHAT EXPENSES SHOULD BE DISALLOWED FOR RATEMAKING PURPOSES?

A TECO's Response to OPC's Third Set of Interrogatories No. 31, indicates that Performance Restricted Shares are awarded based on TECO Energy total shareholder return. No factors related to the operation of TECO are identified as being relevant to the awarding of Time-Vested Restricted Shares. Therefore, I recommend that 100% of the cost of those two awards be removed from test year expenses. Stock compensation on Schedule C-35, line 15 for 2009 is shown as $2.6 million and that amount should be excluded.

I would also recommend the disallowance of 100% of officer and key employee cash payments because those payments are contingent upon TECO Energy achieving a specific level of net income. Additionally, a portion of the general employee-based incentive pay also should be excluded from allowable operating expenses because it is based upon financial goals of both TECO and TECO Energy, the parent. I recommend that 50% of the incentive compensation be disallowed. Based upon the 2007 incentive compensation payout of $12.9 million, the additional disallowance would be $6.45 million. In total, I recommend a reduction of $9.05 million in the allowance of incentive compensation on the basis that such compensation is for the benefit of shareholders rather than ratepayers.

3. CLASS COST-OF-SERVICE STUDY

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

A A cost-of-service study is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost-of-service. 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.

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.

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 (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 BETWEEN 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, and the amount of electricity that a customer uses. 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.

These three factors explain why some customers pay higher 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 also 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.

Q **HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY TECO FILED IN THIS PROCEEDING?**

A Yes.

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

A With the exceptions I will discuss below, yes. TECO's class cost-of-service study recognizes the different types of costs as well as the different ways electricity is used by various customers.

Q **DO YOU AGREE WITH ALL OF TECO'S PROPOSED ALLOCATION METHODS?**

A No. I disagree with the following TECO proposals:

- The consolidation of the GSD, GSLD, and IS classes;
- Classifying the Big Bend scrubber and Polk Unit 1 gasifier investments to energy, rather than demand; and
- The 12 Coincident Peak and 25% Average Demand (12CP-25%AD) method of allocating production plant.

Finally, even though the Commission approved TECO's proposal to increase the Energy Conservation Cost Recovery (ECCR) surcharge in Docket No. 08802 EI to allow the recovery of Rider GSLM-2 and GSLM-3 credits, these credits are not allocable to interruptible customers. I will explain later in this section why interruptible customers should not be charged for any of these credits.

Q **WHAT PORTION OF PRODUCTION PLANT COSTS WOULD BE ALLOCATED TO ENERGY UNDER TECO'S CLASSIFICATION/ALLOCATION PROPOSALS?**

A Taking all production plant costs into account, including costs recovered through the ECRC, TECO's proposals in this base rate case would result in allocating 43% of these costs to energy.

Q. **IS THIS ALLOCATION APPROPRIATE?**

A No. TECO is placing undue emphasis on year-round energy, or annual average demand, rather than peak demand. As explained later, peak demand drives the need to install operable generation capacity. Annual average demand is not a cost driver.

GSD, GSLD, IS Class Consolidation

Q WHY IS TECO PROPOSING TO CONSOLIDATE THE GSD, GSLD, AND IS CLASSES?

A TECO bases its request to consolidate these classes on two proposed rate design changes. First, TECO proposes to eliminate Schedule IS (Interruptible Service) and to price this service under Rider GSLM-2 (GSLM-3 for standby service). It asserts that the GSLM are riders to Schedule GSD. Second, TECO asserts that the present GSD and GSLD base rate charges for energy and demand are nearly identical, with the only real difference being the customer charge that reflects the different percentage of customers taking service at a higher voltage level, and the application of a power factor clause for GSLD.

Q. IS CONSOLIDATION OF THESE CLASSES APPROPRIATE?

A No. As previously explained, customer classes should be homogeneous according to their usage patterns and service characteristics. While TECO asserts that there are minimal differences between the current GSD and GSLD prices, it fails to show that there are no significant differences in either usage patterns or service characteristics among GSD, GSLD, and IS customers.

Q DOES TECO'S PROPOSED CHANGE (WHICH FIPUG AND MOSAIC OPPOSE) IN THE PRICING OF INTERRUPTIBLE SERVICE JUSTIFY TRANSFERRING SCHEDULE IS CUSTOMERS TO SCHEDULE GSD?

A No. The design of riders GSLM-2 and GSLM-3 is not tied to a specific firm rate design, such as GSD. Thus, there is no connection whatsoever between pricing interruptible service on these riders and the proposed consolidation of the GSD, GSLD, and IS classes.

Q ARE THE GSD, GSLD, AND IS CLASSES HOMOGENEOUS?

A No. **Exhibit ___(JP-5)** is an analysis of the characteristics of GSD, GSLD, and

IS classes. The key characteristics include: size, load factor, coincidence factor, and delivery voltage. The analysis is summarized in the table below. As can be seen, there are significant differences in each of the key characteristics.

Description	GSD	GSLD	IS
Size:			
kW per Customer	1,051	22,865	52,746
kWh per Customer	380,000	11,468,000	24,898,000
Coincident Load Factor	68.6%	79.5%	95.6%
Coincidence Factor	71.8%	86.5%	67.6%
Percent of Sales at:			
Secondary	98%	54.4%	0%
Primary	2%	45.2%	46%
Sub-transmission	0%	0.4%	54%

Q **WHAT IS COINCIDENCE FACTOR?**

A Coincidence factor is the ratio of coincident demand to billing demand. It measures how much of a customer's peak demand occurs coincident with the system peak.

Q **HOW IS COINCIDENCE FACTOR RELEVANT IN DETERMINING WHETHER CUSTOMER CLASSES ARE HOMOGENEOUS?**

A Differences in coincidence factor have important rate design implications. Specifically, a lower coincidence factor means that it is less costly to serve a customer on a per kW basis. The higher the coincidence factor, the higher the demand charge when the charge is based on maximum demand. This result is illustrated on the next page. Coincident demand is the primary basis upon which production, transmission and distribution costs are allocated among the customer classes. Billing or non-coincident demand is the maximum metered demand during the billing month.

Relationship Between Coincidence Factor and Demand Charges					
Customer Class	Coincident Demand (kW)	Billing or Non-Coincident Demand (kW)	Coincidence Factor[(a)]	Allocated Demand Costs[(b)]	Demand Charge[(c)]
	(1)	(2)	(3)	(4)	(5)
1	1,000	2,000	50%	$10,000	$5.00
2	1,000	1,430	70%	$10,000	$6.99
3	1,000	1,175	85%	$10,000	$8.51
(a) Column (1) ÷ Column (2)					
(b) Assume that costs are allocated in proportion to Column (1).					
(c) Column (4) ÷ Column (2)					

As can be seen, the lower the coincidence factor, the lower per unit demand charge, all other things being equal. This is because there are more billing units (Column 2) over which to spread the allocated demand-related costs (Column 4).

Q **WHAT IS THE IMPLICATION OF THE DIFFERENT COINCIDENCE FACTORS IN DETERMINING WHETHER THE GSD, GSLD, AND IS CLASSES SHOULD BE COMBINED?**

A As shown previously, the GSD, GSLD, and IS classes have very different coincidence factors. Ignoring all of the other differences, combining these three classes would result in inappropriate cross subsidies.

Q **ARE THERE OTHER REASONS THE GSD, GSLD, AND IS CLASSES SHOULD NOT BE COMBINED?**

A Yes. The IS class is much larger than either the GSD or GSLD classes. IS customers take a preponderance of service at sub-transmission voltage, whereas virtually no electricity is provided to GSD or GSLD customers at this high voltage level. Further, IS customers have much higher coincident load factors than GSD or GSLD customers. The higher coincident load factor means that more energy is purchased during off-peak hours. And finally, as explained later, applying the

GSLD rates to the IS class will result in the IS class earning a much higher rate of return than the GSLD class.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION ON TECO'S PROPOSAL TO CONSOLIDATE THE GSD, GSLD, AND IS CLASSES.

A The Commission should not consolidate these classes. The proposed class consolidation is not supported because there are dramatic differences in class load and service characteristics. While this is one of the criteria that Mr. Ashburn references in describing a proper rate design,[21] he has failed to follow his own criterion in this instance. The IS class should remain intact regardless of how interruptible service is priced.

<u>Polk Unit 1 Gasifier</u>

Q HOW DOES TECO PROPOSE TO CLASSIFY THE INVESTMENT AND RELATED EXPENSES OF THE GASIFIER AT POLK UNIT 1?

A TECO proposes to classify the gasifier train equipment (gasifier) to energy. Polk Unit 1 is an integrated gasified combined cycle (IGCC) facility. In explaining this treatment, Mr. Ashburn states that the gasifier converts coal as the fuel feedstock into gas used in the power block and thus performs a fuel conversion function.

Q SHOULD THE POLK UNIT 1 FUEL CONVERSION EQUIPMENT BE CLASSIFIED TO ENERGY?

A No. All power plants are built to produce capacity when it is needed to serve load and maintain reliability. However, the need for power plants is dictated by the projected peak demand, not the annual energy requirements. This is no less true for Polk Unit 1. In approving a determination of need for this unit, the Commission found that:

> TECO's reliability criteria will not be met unless the proposed IGCC unit is completed in the time frame requested.
>
> * * *

> Thus, the addition of capacity from the proposed IGCC unit is needed for TECO to maintain acceptable reliability criteria.
>
> *   *   *
>
> TECO's proposed 220 MW IGCC unit is also needed to contribute to the reliability and integrity of the electric system of the State as a whole.[22]

In other words, the entire plant (including the gasifier) is needed to meet projected peak load growth and maintain reliability. Thus, it was peak demand, not year-round energy that caused the capacity of Polk Unit 1 and the rest of TECO's generation fleet to be built. Without the growth in peak demand, Polk Unit 1 and other capacity would not be needed. Therefore, the gasifier should be classified to demand and not to energy.

Q. WOULD CLASSIFYING THE GASIFIER TO DEMAND BE CONSISTENT WITH THE COST OF SERVICE PRINCIPLES YOU DISCUSSED ABOVE?

A. Yes. Mr. Ashburn has selectively chosen only one component of Polk Unit 1 for this special, and inappropriate, treatment. It can be said that the land, turbine generators, step-up transformers, and structures of every TECO power plant have all been sized to provide the capacity needed to meet peak demand. Yet, Mr. Ashburn proposes to allocate 25% of these costs to energy. Further, most of the remaining costs would be allocated to spring and fall months as a consequence of using the 12CP method. As explained later, TECO experiences its annual system peaks during the summer and winter months. These are the demands that drive TECO's capacity planning process. The 12CP method, on the other hand, allocates production plant costs to each of the twelve months in a calendar year.

Thus, it is improper and inconsistent with cost of service principles to selectively choose one component of one plant, the Polk Unit 1 gasifier, without also recognizing that other plants and plant components are caused by the need to meet annual peak demands.

Q **DOES IT FOLLOW THAT THE INVESTMENT IN THOSE POWER PLANT COMPONENTS DESIGNED TO CONVERT FUEL INTO ENERGY SHOULD BE CLASSIFIED TO ENERGY?**

A No. All power plants physically convert fuel into energy. For example, coal is received, processed and transported into the boilers to produce steam (another form of energy) at the Big Bend Units. It is this steam that is used to provide the energy to rotate the turbine generator, which in turn generates electricity. Despite this similarity to the Polk Unit 1 gasifier, there is no debate that the individual components of a power plant are *sized* to provide the capacity need for TECO to meet peak demand and provide reliable service. Thus, they should not be classified to energy.

For all of the above reasons, the Polk gasifier should be classified to demand.

12CP-25% AD Method

Q **WHAT METHOD DOES TECO ASK THE COMMISSION TO APPROVE TO ALLOCATE PRODUCTION PLANT COSTS?**

A TECO asks this Commission to approve the 12CP-25% AD methodology for allocating production plant costs to the retail customer classes.

Q **HAS THIS COMMISSION EVER APPROVED THE 12CP-25% AD METHOD ?**

A No.

Q **WHAT METHOD HAS THE COMMISSION PREVIOUSLY APPROVED?**

A In past rate cases, the Commission has approved the 12CP-1/13th AD method. The Commission used this method in TECO's most recent base rate case (with the exception of the Big Bend scrubbers) and uses this method in both the ECCR and Capacity Cost Recovery (CCR) clauses.

Q **WHAT IS THE 12CP-25% AD METHOD?**

A The 12CP-25% AD method classifies 75% of production plant costs as demand-related and 25% as energy-related. The 12CP method is then used to allocate those capacity costs classified to demand, while annual energy usage, or average demand, is used to allocate those capacity costs classified to energy.

Q **WHAT REASON DOES TECO OFFER FOR ASKING THE COMMISSION TO CHANGE TO THE 12CP-25% AD METHOD TO SET RATES IN THIS PROCEEDING?**

A TECO argues that the 25% weighting to average demand represents a "balance" between the "inadequate" 12 CP-1/13th AD and Equivalent Peaker (EP) methodologies. Specifically, Mr. Ashburn cites the substantial base load and intermediate generation that TECO has built to serve load. TECO's investment in base load and intermediate capacity is generally higher in cost on a per kW basis than the corresponding investment in peaking capacity. He further argues that TECO has significant production plant investment related to environmental concerns, which he asserts is incurred more as a function of the energy utilization of a production facility than its peak capability. The bottom line of Mr. Ashburn's contention is that higher investment or capital costs are incurred to save energy costs. The notion that a utility is said to "substitute" capital investment for fuel savings is often referred to as the theory of "Capital Substitution." The EP method was a specific application of Capital Substitution theory.

Q HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE EQUIVALENT PEAKER (EP) METHOD?

A Yes. This Commission has previously rejected the EP method. Specifically, the Commission stated that:

> The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours past the break-even point.[23]

Thus, the Commission recognized that allocating the extra plant investment associated with generating units that provide fuel cost savings (*e.g.,* base load and intermediate capacity) to energy usage beyond the economic break-even point is at odds with the utility planning process. This is because <u>all</u> production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of capability to install. I will explain why this is so below.

Q WHAT IS MEANT BY THE "BREAK-EVEN POINT?"

A The break-even point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same. The illustration is based on a break-even point of 1,000 hours. This reflects the fact that peaking units rarely operate more than 1,000 hours per year on a recurring basis.

Q WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?

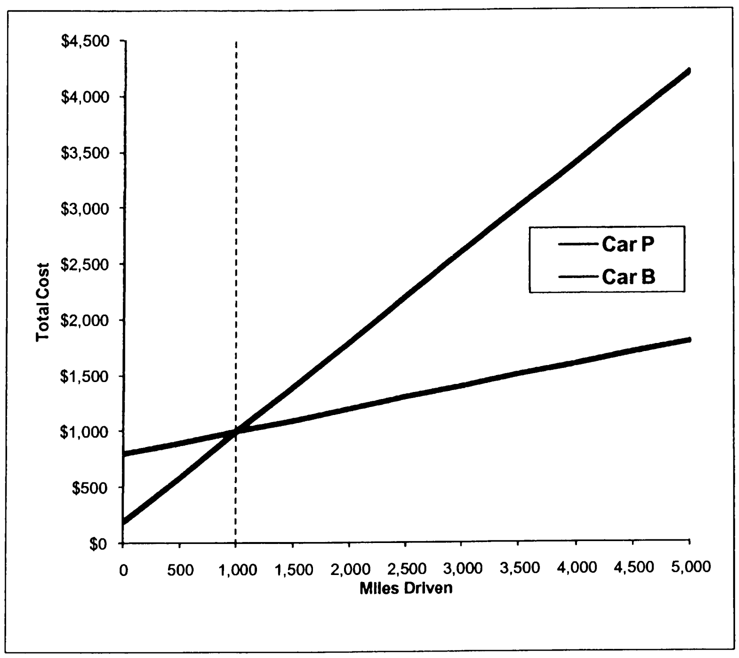
A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

To provide an analogy, suppose two different customers are required to rent cars from a fleet that contains only two types of cars, "Car P" and "Car B":

	[redacted]	Car B
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high mileage (like a base load plant), while the Car P has a low fixed charge but gets poor mileage (like a peaking unit). The graph below shows total cost of both cars over a range of miles driven.



The total cost is also calculated in the table below.

Miles Driven	Total Cost			Best Choice
			Car B	
0	$200		$800	
500	$600		$900	
1,000	$1,000		$1,000	P or B
1,500	$1,400		$1,100	B
2,000	$1,800		$1,200	B
2,500	$2,200		$1,300	B
3,000	$2,600		$1,400	B
3,500	$3,000		$1,500	B
4,000	$3,400		$1,600	B
4,500	$3,800		$1,700	B
5,000	$4,200		$1,800	B

As can be seen, the break-even point between Car P and Car B is 1,000 miles. That is, the higher mileage Car B has a lower total cost per mile than the Car P if it operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose the same car, Type B. The 12CP-25% AD, however, would charge the second customer about 47% more solely because that customer needed to drive three times as many miles. This result is arbitrary and inequitable because the Type B car was the more economical choice for both customers.

Q **DOES THE 12CP-25% AD METHOD REFLECT COST-CAUSATION CONSISTENT WITH THE BREAK-EVEN POINT CONCEPT?**

A No. As previously stated, TECO is proposing to classify and/or allocate 43% of production plant costs to energy. The 25% AD portion is shown in **Exhibit ___(JP-6)**. As can be seen, the 25% AD has the effect of allocating substantial costs beyond the break-even point. Further, some of the 12CPs fall outside of the hours that peaker units operate. Thus, the 12CP-25% AD is totally contrary to capital substitution theory. The Commission should (once again) not endorse a cost allocation method which, on its face, is inconsistent with system planning principles, the underlying theory of capital substitution, and past precedent.

Q DOES THE 12CP-25% AD METHOD HAVE ANY OTHER FLAWS?

A Yes. The 12CP-25% AD method would be used to allocate all production plant costs, irrespective of the type of resource. This would include plant costs associated with the combustion turbine (CT) units. Further, TECO is also proposing to apply this method to allocate the dispatchable costs recoverable in the ECCR. This would include GSLM-2/3 payments as discussed below. Both CTs and GSLM resources provide peaking capacity and are not incurred to achieve lower fuel costs. Finally, this method is not consistent with TECO's load and supply characteristics.

Q IS THE 12CP-25% AD CONSISTENT WITH CAPITAL SUBSTITUTION THEORY?

A No. In addition to allocating costs beyond the break-even point, TECO's proposed application would fail to fully reflect capital substitution theory.

Q WHY DO YOU CONTEND THAT THE 12CP-25% AD FAILS TO FULLY REFLECT CAPITAL SUBSTITUTION THEORY?

A Mr. Ashburn implements capital substitution theory by altering the method in which production plant-related costs are allocated among the retail customer classes. The result of applying capital substitution in this fashion is to allocate above-average plant investment to high load factor customer classes and below-average investment to lower load factor customers. This is shown in **Exhibit _____ (JP-7)**. As can be seen, TECO's average production investment is $553 per 12CP kW. The RS and GS classes have been allocated net investment less than $530 per kW, while the allocations to other classes would range from $561 per kW to over $1,300, which is above the average.

However, Mr. Ashburn fails to apply capital substitution theory to allocate production operating expense. That is, the 12CP-25% AD erroneously assumes that customers should be charged average or "slice of the system" fuel costs. A slice of the system means that each class is served from the same mix of base load and peaking capacity. Thus, each class would pay the same average fuel charge, or 5.93¢ per kWh

Q **WHY IS THIS APPROACH INCONSISTENT WITH CAPITAL SUBSTITUTION THEORY?**

A There is a symmetrical relationship between plant investment and operating expense. This relationship is shown in **Exhibit ____ (JP-7)**, page 2. On average, TECO's net production investment is $442 per kW of winter capacity. The average fuel expense associated with this investment is $5.46¢ per kWh. As can be seen, the capacity that TECO classifies as base load (line 1) has a net plant investment of $558 per kW and associated fuel expense of $3.95¢ per kWh. The corresponding costs for peaking capacity are $309 per kW, and 14.88¢ per kWh. The base load capacity, thus, has a higher plant investment but a lower operating expense, on a per unit basis. The opposite is true for TECO's peaking capacity (line 3).

Given the symmetrical relationship, the application of capital substitution theory would not be complete unless the allocation and recovery of fuel expense was consistent (symmetrical) with the corresponding allocation of plant investment. This means that a class that is allocated a larger share of production plant investment should also receive more of the associated benefits of the lower operating costs of base/intermediate capacity. Stated differently, if a class is allocated above-average plant investment per kW, then consistency demands that this same class be allocated below average operating expense (fuel and variable O&M) per MWh. This would explicitly recognize the symmetrical relationship between plant investment and operating expense.

Consider again the analogy of the two cars (P and B) with different fuel efficiencies and fixed costs. The customer who drives the car only a few miles (low load factor) would incur a higher average mileage charge than the customer that drives many miles per day (high load factor). This symmetrical relationship is consistent with capital substitution theory.

Q **DO TECO'S LOAD CHARACTERISTICS SUPPORT USE OF THE 12CP-25% AD METHOD?**

A No. TECO experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit ____ (JP-8_)**, page 1, which is an analysis of TECO's monthly firm peak demands as a percent of the annual system peak for the years 2003 through 2007. The peak demands in the other months are typically well below the summer and winter peak demands.

These characteristics are further summarized in **Exhibit ____ (JP-8)**, page 2. As can be seen:

- The minimum month peak is consistently below 70% of the annual system peak.
- Monthly peak demands are only 85% of the annual system peak.
- Summer peak demands are 20% (or higher) of the non-summer peak demands.
- And with one exception, TECO's annual load factor is at or below 60%.

These ratios confirm that TECO has seasonal load characteristics. Thus, electricity demands in the spring and fall months are not relevant in determining the amount of capacity needed for TECO to provide reliable service.

Q ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE TECO HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?

A No. Although TECO does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, TECO generally has higher reserve margins during the non-summer months than during the summer months. This is shown in **Exhibit ___(JP-9)**. The reserve margins were calculated as the margin (available capacity less scheduled outages less firm peak demand) divided by firm peak demand. As can be seen, the summer month reserve margins, adjusted for scheduled outages, have been well below the corresponding non-summer month reserve margins.

Q WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?

A The analyses demonstrate that the summer peak demands, and to a lesser extent the winter peak demand, determine TECO's capacity requirements. The spring and fall months are irrelevant. Thus, the 12CP method does not reflect cost-causation when measured by TECO's load and supply characteristics.

Q PLEASE SUMMARIZE THE REASONS THAT IT IS INAPPROPRIATE TO USE THE 12CP-25% AD METHOD TO ALLOCATE PRODUCTION CAPITAL COSTS TO THE VARIOUS RATE CLASSES.

A First, the 12CP-25% AD method results in 43% of production plant costs being allocated based on year-round energy usage, taking into account costs recovered in base rates and through the ECRC. The assumption that year-round energy usage causes higher production capital investment is totally inaccurate and flawed. As discussed above, investment decisions are <u>not</u> caused by energy usage. At most, they are influenced by load duration but only up to the break-even point between different types of capacity. Therefore, allocating production investment on energy utilization, as is the case under the 12CP-25% AD, is a flawed application of capital substitution theory.

Second, there is no symmetrical allocation of fuel costs which is required because the 12CP-25% AD allocates a larger share of base load plants, which have both above-average investment and below-average fuel costs. TECO's cost study makes no effort to change the way that fuel costs are allocated and recovered from customer classes. Currently, each class pays the same average fuel costs, which is the same allocation as in methodologies that do not explicitly recognize system planning principles. Absent a symmetrical allocation of investment and operating costs, which would result in below-average fuel costs per kWh being assigned to those classes that are also assigned above-average investment per kW, the 12CP-25% AD is an incomplete and inaccurate representation of capital substitution theory.

Finally, TECO has seasonal load characteristics, and it experiences its lowest reserve margins during the summer and winter peak months rather than during the spring and fall months. For these reasons, the 12CP method cannot be justified solely on the basis of the summer and winter peak months that are driving TECO's capacity needs.

Q YOU STATED EARLIER THAT THE COMMISSION HAS PREVISOULY APPROVED THE 12CP-1/13TH AD METHOD. WHY DID THE COMMISSION SELECT THIS METHOD?

A It is my understanding that the Commission originally adopted the 12CP-1/13th AD method to recognize the same economic theory that Mr. Ashburn associates with the 12CP-25% AD. Although the 12CP-1/13th AD allocates production investment beyond the break-even point, it does so only minimally. It also recognizes that load duration is a driver that determines utility investment decisions.

Q WHICH OF THE TWO METHODS, 12CP-1/13TH AD OR 12CP-25% AD, COMES CLOSER TO REFLECTING UTILITY SYSTEM PLANNING PRINCIPLES?

A While neither method perfectly reflects system planning principles, the 12CP-1/13th AD method (with the Big Bend Scubber and Polk gasifier costs classified to demand) would come much closer to recognizing cost-causation and the economic theory underlying generation expansion planning (i.e., capital substitution). TECO's proposed production plant classification/allocation methodology is nothing more than an unsupported "compromise" between the currently approved 12CP-1/13th AD method and the previously discredited Equivalent Peaker method. For this and all of the above reasons, the Commission should reject the 12CP-25% AD method in this proceeding.

<u>Environmental Costs</u>

Q IS TECO PROPOSING TO RECOVER ANY ENVIRONMENTAL COSTS IN BASE RATES?

A Yes. TECO proposes to recover the scrubber portion of the Big Bend Unit 4 environmental equipment in base rates.

Q HOW DOES TECO PROPOSE TO ALLOCATE THE BIG BEND 4 SCRUBBER COSTS?

A TECO proposes to classify and allocate the entirety of these costs to energy.

Q MR. ASHBURN ARGUES THAT CLASSIFYING ENVIRONMENTAL COSTS TO ENERGY CAPTURES THE PRODUCTION COST IMPACT OF HIGHER LOAD FACTOR AND INTERRUPTIBLE CUSTOMERS WHO BENEFIT FROM THE LOWER VARIABLE COSTS OF BASE AND INTERMEDIATE LOAD UNITS. DO YOU AGREE?

A No. This argument is inconsistent with well-known principles of cost-causation. The proper application of cost-causation is to identify the specific usage characteristics that cause the utility to incur production plant and related expenses. While environmental concerns may be reflected in the investment in production equipment and may influence production operating expenses, they are a prerequisite to plant operation. In other words, a plant could not be legally operated to provide either capacity or energy unless it was in full compliance with all applicable environmental regulations. Thus, environmental concerns do not alter the fundamental reasons that cause electric utilities to install generation capacity: namely, to meet the projected peak demand for electricity and load duration up to the break-even point.

In addition to being directly related to production plant, pollution control investments are primarily fixed. They vary directly in proportion to the size (*i.e.*, the capacity) of a generating unit. More importantly, other than some operation and maintenance expenses, these costs do not vary with energy usage. Therefore, the cost characteristics of pollution control equipment do not support the classification of production plant costs to the energy function.

Q DID THE COMMISSION ORDER THAT THE BIG BEND SCRUBBERS BE CLASSIFIED TO ENERGY IN TECO'S LAST RATE CASE?

A No. The ratemaking treatment of the Big Bend scrubbers was stipulated to in TECO's last rate case, Docket No. 92-0314.[24]

Q HOW SHOULD THE BIG BEND SCRUBBER COSTS BE CLASSIFIED AND ALLOCATED IN THIS PROCEEDING?

A The Big Bend scrubber costs should be classified 100% to demand and allocated to retail customer classes using the 12CP-1/13th AD method. In other words, the scrubber should not be classified and allocated any differently than the plant.

Q SHOULD THE COMMISSION ALSO CHANGE THE WAY THAT ENVIRONMENTAL COSTS ARE ALLOCATED IN THE ECRC?

A Yes. The 12CP-1/13th AD method should also be used to allocate environmental investments and related costs and fixed operating expenses that are currently recovered in the ECRC.

Q IS THERE ANY PRECEDENT FOR ALLOCATING ENVIRONMENTAL COSTS ON A BASIS OTHER THAN ENERGY?

A Yes. Progress Energy Florida (PEF) and Florida Power & Light Company (FPL) have agreed to allocate some environmental costs on a demand basis.[25] Further, Alabama Power Company and Georgia Power Company allocate environmental costs relative to base rate (non-fuel) revenues.

<u>**Revised Class Cost-of-Service Study**</u>

Q HAVE YOU REVISED THE CLASS COST-OF-SERVICE STUDY TO INCORPORATE THE ADJUSTMENTS YOU HAVE DISCUSSED?

A Yes. A summary of the revised class cost-of-service study at present is presented in **Exhibit ___(JP-10)**. A complete copy of the revised cost-of-service study is provided in my workpapers which will be provided in response to a discovery request.

Q WHAT CHANGES DID YOU MAKE TO TECO'S COST OF SERVICE STUDY?

A I have made three changes:

1. Production plant costs were allocated using the 12CP-1/13th AD method.

2. Big Bend scrubber and Polk Unit 1 gasifier costs were classified 100% to demand.

3. The IS class was treated as firm for both costing and pricing purposes.

<u>Treatment of the Schedule IS Class</u>

Q PLEASE DESCRIBE THE INTERRUPTIBLE CLASS.

A The interruptible class consists of rate schedules IS (interruptible service) and SBI (standby interruptible service). Under these rate schedules, service may be interrupted at TECO's sole discretion when capacity is needed to maintain service to its firm customers.

Q IS INTERRUPTIBLE LOAD THE SAME QUALITY OF SERVICE AS FIRM LOAD?

A No. In addition to the fact that TECO does not plan its capacity additions to serve interruptible load, TECO can cut-off service to interruptible customers at any time for any reason. Schedule IS provides as follows:

> <u>CHARACTER OF SERVICE</u>: The electric energy supplied under this schedule is three phase primary voltage or higher, and is subject to immediate and total interruption whenever any portion of such energy is needed by the utility for the requirements of its firm customers or to comply with requests for emergency power to serve the needs of firm customers of other utilities. Any essential needs the customer must have shall be furnished through a separate meter on a firm rate schedule.[26]

Q PLEASE EXPLAIN THE TREATMENT OF THE SCHEDULE IS CLASS IN YOUR COST OF SERVICE STUDY.

A The interruptible loads were included in the 12CP demands used to develop the class allocation factors. Because this treatment assumes for costing purposes that Schedule IS customers are receiving firm service, it is both logical and consistent to re-state the Schedule IS revenues at the firm service rates. In this instance, I re-priced IS at the current Schedule GSLD rate. This is shown in **Exhibit___(JP-11)**. The difference between the restated and actual current Schedule IS revenues reflects the amount of interruptible "credits" currently being paid to Schedule IS customers. As can be seen, current Schedule IS/SBI rates are $22.9 million below the corresponding firm (Schedule GSLD/SBF) rates.

Q **WHY SHOULD THE INTERRUPTIBLE CREDITS BE ALLOCATED ONLY TO THE FIRM CUSTOMER CLASSES?**

A Production capacity costs should not be allocated to interruptible customers because they do not cause such costs to be incurred. There are two basic ways to accomplish this. The first is to exclude interruptible load from the cost-of-service study. The second method, which is the approach I have taken, is to include interruptible load as if it were firm, but then to spread the amount of the interruptible credits to the firm classes in the cost-of-service study. The two treatments are mathematically equivalent, as illustrated in **Exhibit ___(JP-12)**.

The illustration shows the allocation of $10,000 in production capacity costs to two equal size classes: A and B. Class A is comprised of only firm load, while Class B's load is 50% firm and 50% interruptible. The interruptible load provides $1,500 in revenue. Method 1 allocates zero production capacity costs to interruptible customers (line 8). The revenues provided by interruptible customers are used to lower the cost to provide firm service (line 9). This results in allocating the $10,000 as follows: Class A $5,667; Class B $4,333 ($2,833 plus $1,500), of which the firm load would be charged $2,833.

Method 2 treats interruptible load as firm, but allocates the interruptible credits only to firm load. The interruptible credits are the difference between the revenues at firm rates (or $2,500) and the revenues paid by the interruptible customers (or $1,500). Thus, in the illustration, the interruptible credits are $1,000. As can be seen on line 13, the $10,000 of production capacity costs is allocated as follows: Class A $5,667; Class B $4,333 ($2,833 plus $1,500), of which firm Class B customers are allocated $2,833. However, this is the same allocation as if no production capacity costs were allocated to interruptible customers in the first place (*i.e.*, Method 1).

Q **WHAT DOES THIS EXAMPLE DEMONSTRATE?**

A The example demonstrates that the costs of providing interruptible service should be allocated in proportion to *firm* loads. It would be inappropriate to allocate the credits to total loads, including interruptible load, because that would effectively charge interruptible customers for the production plant they avoid. This would be contrary to the principle of cost-causation and regulatory precedent. Yet, TECO is proposing to spread these costs to all customers, including interruptible customers, in the ECCR.

Q **WHY IS TECO'S PROPOSAL TO REQUIRE INTERRUPTIBLE CUSTOMERS TO PAY FOR A PORTION OF THEIR OWN CREDITS CONTRARY TO ACCEPTED REGULATORY PRACTICE?**

A TECO's proposal would, in effect, be identical to allocating production capacity costs to interruptible customers. This proposition was recently considered and unequivocally rejected by the Federal Energy Regulatory Commission (FERC). The FERC has traditionally excluded interruptible load from the allocation of production capacity-related costs. This long-standing practice is described in the following excerpt from the recent FERC order rejecting a proposal by Entergy to allocate capacity costs to interruptible load:

> 61. The Initial Decision overlooks that Entergy bases the recovery of its costs on the coincident peak recovery method, in which Entergy allocates its costs among its customers according to each

customer's share of the System load at the time of the System peak. **It assesses its capacity costs to peak period users because it is peak demand that determines how much Entergy will invest in capacity.** [FN116] In Kentucky Utilities, the Commission explained the theory behind this method of cost allocation. A utility builds its bulk power facilities, i.e., generating units and transmission lines, to meet the maximum or peak demand of its firm customers. **Because the utility incurs the cost of these facilities to meet the peak demand of its firm customers, those customers should pay for the facilities. The peak responsibility method accomplishes this by allocating the cost of the facilities among the firm customers in the same proportion as each customer's demand bears to the system peak. [FN117] In contrast, as explained below, a utility need not build to meet its interruptible demand.**

62. **The Commission thus traditionally has not "allocated" the cost of facilities to interruptible load**.

* * *

63. Since Entergy can curtail interruptible service so that it does not contribute to the System peak, **interruptible load does not determine how much Entergy must invest in capacity to meet the System peak, i.e., its customers' needs. Therefore, under the peak load responsibility cost allocation method, Entergy should not include interruptible load in its calculations**.

67. Thus, as explained above, because Entergy did not and does not have to construct capacity to serve interruptible load at the time of its System peak (and thus can and does offer interruptible service at a lower rate), the Initial Decision cannot stand. [FN121] Moreover, the cost recovery system that the Initial Decision adopts [FN122] is without foundation. There is no evidence that Entergy built capacity to serve interruptible load. While Entergy may have considered interruptible capacity in its planning before 1995, [FN123] it then already had sufficient capacity to meet its load and did not need to construct additional capacity; its most recent capacity additions occurred in the mid-1980's. [FN124] So reference to interruptible load in Entergy's planning documents does not demonstrate that Entergy actually built capacity to serve interruptible load. [FN125]

69. Also, it is uncontroverted that Entergy does not now acquire capacity, and, since at least 1995 has not acquired capacity, to serve interruptible loads. [FN131] The Presiding Judge so found, [FN132] and no one disputes this finding. [FN133] Since it is clear, then, that firm load currently drives Entergy's capacity acquisitions, there is no credible basis to allocate the cost of capacity to interruptible loads that existed in 1995. For example, in 2000, Entergy needed all of its existing generating capacity, plus 2950 MW, to meet firm load. [FN134] When all capacity is needed

to serve firm load, **there is no logical reason to allocate the cost of this capacity based, in part, on interruptible load - - either pre-1995 or post-1995.**[27]

Q **WOULD ALLOCATING PRODUCTION CAPACITY COSTS TO INTERRUPTIBLE CUSTOMERS BE COMPATIBLE WITH TECO'S OWN SYSTEM PLANNING PRACTICES?**

A No. TECO does not plan to install generating capacity or purchase firm power to provide interruptible service. TECO specifically removes interruptible loads in assessing the need for new capacity.[28] Since TECO does not incur production capacity costs to serve interruptible customers, no such costs should be allocated to them. The fundamental principal of utility cost allocation is that costs are allocated to those customers that cause them to be incurred. Interruptible customers do not cause capacity costs to be incurred, and thus those costs should not be allocated to them.

Q **SHOULD THE COSTS INCURRED TO SUSTAIN INTERRUPTIBLE LOAD BE ALLOCATED DIFFERENTLY IF THESE COSTS ARE RECOVERED IN BASE RATES OR THROUGH A COST RECOVERY CLAUSE?**

A No. Payments to interruptible customers represent the value of the capacity not built or acquired to serve interruptible load. Thus, they are not caused by or allocable to interruptible customers. This treatment should apply irrespective of whether the cost of providing interruptible service is recovered in base rates or through the ECCR, as TECO is proposing.

Revised Class Cost-of-Service Study Results

Q **PLEASE EXPLAIN HOW THE COST-OF-SERVICE STUDY RESULTS ARE EVALUATED.**

A Cost-of-service study results shown in my revised study (**Exhibit ___(JP-10)** are measured in three ways: (1) rate of return, (2) relative rate of return, and (3) interclass subsidies.

Rate of return (line 29) is the ratio of net operating income (revenues less allocated operating expenses as shown in line 18) to the allocated rate base (line 27). Net operating income is the difference between operating revenues at current rates (line 6) and allocated operating expenses (line 16). If a class is presently providing revenues sufficient to recover its cost-of-service (at the current system rate of return), it will have a rate of return equal to or greater than the total system return of 5.00%.

Relative rate of return (RROR), which is shown on line 31, is the ratio of each class' rate of return to the Florida Retail average rate of return. A relative rate of return above 100 means that a class is providing a rate of return higher than the system average, while a relative rate of return below 100 indicates that a class is providing a below-system average rate of return.

Subsidy (line 33) measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

Q WHAT DO THE RESULTS OF YOUR REVISED CLASS COST-OF-SERVICE STUDY SHOW?

A The IS class is producing the highest ROR (nearly twice the system average) of any customer class *before* TECO's proposed base rate increase.

Q WHAT IMPLICATIONS DO THESE RESULTS HAVE IN THIS CASE?

A Even with no base rate increase, this class is currently providing a higher ROR than TECO is requesting in this proceeding. Thus:

- The cost of providing firm service to Schedule IS customers is below the current Schedule GSLD pricing; and

- It is not appropriate to consolidate the IS and GSLD/GSD classes because it would result in Schedule IS customers subsidizing the firm service rates of Schedule GSLD/GSD customers.

4. CLASS REVENUE ALLOCATION

Q **WHAT IS CLASS REVENUE ALLOCATION?**

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

Q **HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE SPREAD AMONG THE VARIOUS CUSTOMER CLASSES TECO SERVES?**

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

Q **PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.**

A *Gradualism* is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost-of-service should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q **PLEASE EXPLAIN HOW RATE ADMINISTRATION IS RELATED TO RATE CHANGE.**

A. *Rate administration* is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate.

Q **SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?**

A Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

Q **ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?**

A Yes. The other reasons for adhering to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q **WHY ARE COST-BASED RATES EQUITABLE?**

A Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually *costs* the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q **HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?**

A With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q **HOW CAN COST-BASED RATES PROVIDE STABILITY?**

A When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q **HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?**

A By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just *less use*). If rates are not based on a class cost-of-service study, then consumption choices are distorted.

Q **DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?**

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal. For example,

> The authorized revenue increase is allocated to the rate classes in a manner that moves each class rate of return as close to parity as practicable based on the approved cost allocation methodology, and subject to the following constraints: (1) no class shall receive an increase greater than 1.5 times the system average percentage increase; and (2) no class shall receive a decrease.[29]

Therefore, moving TECO's rates closer to cost would be consistent with Commission policy.

Q **HOW IS TECO PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?**

A TECO's proposed base revenue increase is shown in **Exhibit ___(JP-13)**. As can be seen on page 1, TECO is proposing a 26.4% base rate increase. The increases by rate would range from 7.9% for Lighting Facilities to 134.3% for the interruptible (Schedule IS/SBI) class.

Q **WOULD INTERRUPTIBLE CUSTOMERS EXPERIENCE 134% BASE RATE INCREASES?**

A The answer depends on the level and structure of the interruptible credits that will be provided under the GSLM-2 and GSLM-3 riders. As discussed later, TECO's proposal to provide interruptible service under these riders will subject interruptible customers to periodic base rate changes. Based on the riders that

TECO proposes for 2009, interruptible customers would experience an "effective" base revenue increase of 35.5%. The corresponding increases for all rate classes is shown on page 2 of **Exhibit ___(JP-13)**. The difference between page 2 and page 1 is the assumption that Rider GSLM-2 & 3 payments would be recovered in the ECCR (see Column 3). As can be seen, interruptible customers would receive the second highest base rate increase of any rate class.

Q **HOW SHOULD ANY RATE INCREASES OR DECREASES RESULTING FROM THIS CASE BE ALLOCATED AMONG THE VARIOUS CLASSES?**

A Consistent with Commission policy and precedent, rates for each class should be set at a level that will recover the cost of serving that class. Under my revised class cost-of-service study, interruptible base rates should be reduced. The same is true of Lighting Facility rates.

To avoid rate shock and to reflect gradualism considerations, I propose that no rate class should receive a base rate decrease. This is reflected in **Exhibit ___ (JP-14)** using TECO's proposed revenue requirement.

Q **WOULD YOUR RECOMMENDED REVENUE ALLOCATION MOVE ALL CLASSES CLOSER TO COST?**

A Yes. This is shown in **Exhibit ___(JP-15)**, which shows the cost-of-service study results under my recommended class revenue allocation. As can be seen, all but one class would be moved very close to cost. The lighting facility class would move 63% closer to cost.

5. FIRM RATE DESIGN

Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A In this section, I will discuss the appropriate design of the firm rates. Non-firm rate design is addressed in Part 5. Specifically, I will discuss:

- The Demand and Non-Fuel Energy charges; and
- The Transformer Ownership Discounts.

<u>**Demand and Non-Fuel Energy Charges**</u>

Q DESCRIBE THE DEMAND AND NON-FUEL ENERGY CHARGES.

A These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the non-fuel energy charges are billed on the kWh purchased.

Q DO YOU AGREE WITH HOW TECO HAS PROPOSED TO DEVELOP THE DEMAND AND NON-FUEL ENERGY CHARGES?

A No. Consistent with cost-causation, TECO's demand-related costs should be recovered through the demand charge, and energy-related base rate costs should be collected through the energy charge. TECO has underpriced the demand charge and overpriced the energy charge (based on TECO's proposed revenue levels). The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study.

Q WHAT ARE THE UNIT ENERGY COSTS DERIVED FROM YOUR REVISED CLASS COST-OF-SERVICE STUDY?

A The unit costs from the revised class cost-of-service study are shown in **Exhibit ___ (JP-16)**. As can be seen, the Schedule IS non-fuel energy costs would be

0.75¢ per kWh. TECO's proposed non-fuel energy charge would be 1.06¢ per kWh, which is substantially above the actual unit cost. Accordingly, I recommend that the non-fuel energy charge be set at the per unit energy cost, or 0.75¢ per kWh.

<u>**Transformer Ownership Discounts**</u>

Q EXPLAIN THE CONCEPT OF TRANSFORMER OWNERSHIP DISCOUNTS.

A TECO's current rates apply to customers that take service at different delivery voltages. However, the base demand and energy charges in Schedules GSD and GSLD are designed to reflect the cost to serve at secondary distribution, while the corresponding Schedule IS base rate charges are designed for service at primary distribution. Thus, to prevent intra-class subsidies, there must be a mechanism to adjust the base charges to reflect the lower cost of providing primary and sub-transmission service.

Q WHAT MECHANISMS ARE APPROPRIATE TO ACCOMPLISH THIS?

A There are two such mechanisms to reflect voltage-differentiated costs in the current tariffs: (1) the Metering Level Discount and (2) the Transformer Ownership Discount. Though the term "discount" is sometimes interpreted as a below-cost rate, both the Metering Level and the Transformer Ownership Discounts are cost-based; that is, they reflect differences in the cost of providing service by delivery voltage. Whereas the Metering Level Discount reflects the differences in losses where electricity is metered (*i.e.,* the utility incurs lower losses to deliver electricity at sub-transmission than distribution voltage), the Transformer Ownership Discount reflects the differences in the cost of the facilities used to provide service.

For example, Schedule GSLD customers served at primary voltage receive a 36¢ per kW credit, which reflects the costs of providing secondary distribution service, which are avoided when the customer supplies the necessary equipment. A GSLD customer served at sub-transmission receives a 59¢ per kW credit. The corresponding credit for a Schedule IS customer is 23¢ per kW. The lower credit is due to the fact that the base rate Schedule IS charges are designed for service at primary, rather than secondary, distribution service. In both cases, however, the latter credits reflect the cost of distribution facilities avoided when a customer takes sub-transmission service.

In summary, the Metering Service and Transformer Ownership Discounts are consistent with cost-of-service principles. They prevent intra-class subsidies by providing lower rates to customers that take service at higher delivery voltages. This is appropriate because the utility does not invest in distribution facilities and it also incurs lower losses to serve sub-transmission customers.

Q **WHAT CONCERNS DO YOU HAVE ABOUT THE PROPOSED TRANSFORMER OWNERSHIP DISCOUNT?**

A The proposed credits are understated because TECO divided the avoided cost by "ratcheted" rather than actual billing demand. The ratcheted demands were assumed to be 22% higher than the billing demand. However, there are no demand ratchets in TECO's tariffs. Thus, a cost-based credit should reflect actual billing demands.

Q **HOW WOULD USING BILLING DEMANDS AFFECT THE PROPOSED TRANSFORMER OWNERSHIP DISCOUNT?**

A The analysis is shown in **Exhibit ___(JP-17)**. The calculation is identical to TECO's, as found in TECO's response to FIPUG's Production of Document Request No. 20, but for substituting actual rather than ratcheted billing demands on lines 21 and 48.

6. INTERRUPTIBLE RATES

Q **WHAT IS INTERRUPTIBLE POWER?**

A Interruptible power is a tariff option that allows a utility to curtail interruptible load when resources are needed to maintain system reliability; that is, when there are insufficient resources to meet customer demand, a utility can curtail interruptible load. This allows the utility to maintain service to firm (i.e., non-interruptible) customers. Interruptible power, thus, is a lower quality of service than firm power. TECO does not include interruptible load in determining the need for additional capacity. Thus, TECO does not plan capacity additions to serve interruptible load.

Q **DOES INTERRUPTIBLE POWER PROVIDE ANY OTHER BENEFITS?**

A Yes. The Florida Reliability Coordinating Council (FRCC) requires that all reserve sharing groups and balancing authorities maintain adequate Contingency Reserves to cover the FRCC's most severe single contingency, which is currently 910 MW. Of this amount, TECO's contingency reserve requirement is currently 86.4 MW. TECO must supply this reserve when called upon to replace reserve capacity that is no longer available due to sudden forced outages of major generating facilities or the loss of transmission facilities.

Contingency reserves may be comprised of those generating resources and Interruptible Load that are available within 15 minutes. Thus, TECO counts interruptible power in meeting its contingency reserve obligations.[30]

Q **PLEASE SUMMARIZE TECO'S PROPOSED REVISIONS TO ITS INTERRUPTIBLE TARIFFS.**

A TECO proposes to continue to change the design of its interruptible tariffs, which it began in 1999 following Order No. PSC-99-1778-FOF-EI.

First, TECO asks this Commission to allow it to eliminate Schedules IS-1, IS-3, and SBI. The customers currently on these tariffs would be transferred to other rates. IS-1 and IS-3 customers would be transferred to Schedule GSD for firm service and Rider GSLM-2 for interruptible service. (As previously discussed, Schedule IS customers should not be transferred to Schedule GSD because the IS class load and service characteristics substantially differ from the GSD and GSLD classes.) Interruptible standby (SBI) customers would be transferred to Schedule SBF for firm supplemental and standby service and Rider GSLM-3 for standby interruptible service. Thus, all interruptible customers would pay firm rates and receive a credit that is supposed to reflect the value of interruptibility.

Second, the interruptible credit in the GSLM-2 and GSLM-3 Riders would be based on the Contracted Credit Value (CCV). The CCV approximately reflects TECO's avoided cost and is designed to provide a 1.2 benefit-to-cost ratio using the ratepayer impact measure (RIM) test. This is the same treatment accorded to demand-side management (DSM) programs. As discussed later, TECO has understated the capacity benefits Schedule IS customers provide, thereby understating the CCV.

Third, Riders GSLM-2 and GSLM-3 would be re-filed annually based on the then estimate of TECO's avoided costs. If TECO's avoided costs change, the CCV will change. This would subject interruptible customers to continual changes in their base rates. Under TECO's proposal, the CCV would only remain constant for up to three years thus making the rate highly unstable.

Fourth, by transferring all interruptible service to Riders GSLM-2 and GSLM-3, the interruptible credits would be removed from base rates and collected in the ECCR. Thus, TECO would be guaranteed dollar-for-dollar recovery of all capacity payments, including past over- (under) collections.

Fifth, the capacity payments recovered through the ECCR would be allocated to all customers, including the interruptible customers. As previously discussed, payments to interruptible customers are caused by and should be allocated to firm service customers only.

Q **HOW WOULD TECO'S PROPOSALS IMPACT INTERRUPTIBLE CUSTOMERS TAKING SERVICE ON SCHEDULES IS AND SBI?**

A As a consequence of TECO's proposals, Schedule IS/SBI customers would experience a <u>134%</u> base rate increase, before the application of Riders GSLM-2 and GSLM-3. These Riders will offset some portion of the base rate increase. The amount of the offset will depend on (1) the CCV and (2) the customer's monthly billing load factor.

For 2009, the (CCV) would be $10.91 per monthly coincident peak (CP) kW. This would result in net annual payments of about $25.4 million. However, this would be offset by higher ECCR charges of $1 million. The net non-fuel rate increase for 2009 for IS/SBI customers would be 35%. These calculations are shown in **Exhibit ___ (JP-18)**. If TECO's proposals are approved, the IS class would receive the second highest base rate increases. This is despite the fact that the IS class is currently subsidizing other customer classes and is providing a return higher than TECO is seeking in this case.

Q CAN INTERRUPTIBLE CUSTOMERS RELY ON RECEIVING A $10.91 PER KW CREDIT?

A No. Under TECO's proposal, the CCV changes over time due to (1) changes in the CCV and (2) variations in the customer's monthly billing load factor.

The first change is addressed in Paragraph 5 of the Special Provisions paragraph in Riders GSLM-2 and GSLM-3. It states:

> When the customer's Initial Term of service runs out, that customer shall have a new CCV applied then for a new 36 month period. The credit applied shall be the one on file at that time at the FPSC. At any time, at the customer's discretion, the customer may request a new 36 month commitment whereupon their CCV shall be changed to the one then on file at the FPSC and a new Initial Term of 36 months shall be established.

The second change is addressed in the Monthly Credits paragraph of the GSLM-2 and GSLM-3 riders. It states:

> The Interruptible Demand Credit is the product of the Contracted Credit Value (CCV) (set forth in the Tariff Agreement for the Purchase of Industrial Load Management Rider Service) and the monthly Load Factor Adjusted Demand. The Load Factor Adjusted Demand shall be the product of the monthly Billing Demand and the monthly Billing Load Factor. The Billing Load Factor shall be the ratio of the Billing Energy to the monthly Billing Demand times the number of Billing Hours in the billing period. Billing Hours shall exclude any hours during which interruption of service occurred and no Optional Provision Energy was provided.

A customer's monthly load factor can also vary due to changing operating levels. However, as discussed later, load factor is not an appropriate proxy of the amount of load available for interruption.

Q IS THE VARIABILITY OF THESE PAYMENTS PROBLEMATIC?

A Yes. The variability of the capacity payments in the GSLM-2 and GSLM-3 riders is in stark contrast to the current IS/SBI structure. Currently, Schedule IS and SBI customers pay a lower rate that reflects the inferior quality of interruptible service. Thus, the capacity payment is fixed until the next general rate case and the amount of the payment does not fluctuate with a customer's monthly load factor. The changing nature of these payments would subject IS and SBI customers to rate instability.

Q **WHAT SUPPORT DOES TECO PROVIDE FOR PROPOSED RATE DESIGN CHANGES?**

A In support of its proposals, Mr. Ashburn cites Order No. PSC-93-0165-FOF-EI, the Commission Order in TECO's last rate case (Docket No. 920324-EI). This case was filed in 1992 and decided in February 1993, over 15 years ago.

Q **YOU PREVIOUSLY REFERENCED A 1999 COMMISSION ORDER ON INTERRUPTIBLE RATES. WHAT DID THE COMMISSION DECIDE?**

A The Commission granted TECO's petition to close Schedule IS-3 and to allow new interruptible service to be provided under the terms and conditions of Riders GSLM-2 and GSLM-3.[31]

Q **HAS THE WORLD CHANGED SINCE THAT 1999 ORDER WAS ISSUED?**

A Yes. The primary reason the Commission gave for closing Schedule IS-3 and creating the GSLM-2 and GSLM-3 riders was that interruptible load ceased being cost-effective due to declining equipment costs.[32] However, the cost of new generation capacity has increased significantly. The avoided unit being used to establish the $10.91 CCV is estimated to cost $871/kW.[33] By comparison, the installed cost of the Polk CTs is only $228/kW. As demonstrated later, rising equipment costs mean that Schedule IS/IS-3 is currently cost-effective.

Q HOW ELSE HAS THE WORLD CHANGED SINCE 1999?

A Interruptible power has received increasing attention from legislative and regulatory policy makers. I previously cited a FERC Order affirming that no production capacity costs should be allocated to interruptible customers. Interruptible load was also addressed in the Energy Policy Act of 2005 (EPACT 2005). Specifically:

> "(d) DEMAND RESPONSE.—The Secretary shall be responsible for—
> "(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;
> "(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and
> "(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007."
> (e) DEMAND RESPONSE AND REGIONAL COORDINATION.—
> (1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.
> (2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—
> (A) identifying the areas with the greatest demand response potential;
> H. R. 6—373
> (B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;
> (C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and
> (D) identifying specific measures consumers can take to participate in these demand response programs.

Following enactment, the FERC issued Order No. 693 in which it directed NERC to submit a modification to BAL-002 that includes a requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves provided that it is treated on a comparable basis and meets similar technical requirements as other resources providing this service.[34]

Last February, the FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) to improve the operation of organized wholesale electric power markets. One of the improvements discussed in the ANOPR is in the area of demand response and the use of market prices to elicit demand response. In particular, the reforms would further eliminate barriers to demand response.[35]

Demand response is already providing certain ancillary services in various organized markets, including the PJM Interconnection and Electric Reliability Council of Texas (ERCOT). Thus, it is clear that promoting demand response (of which interruptible power is a primary option) is now a preferred policy.

Q **IS INTERRUPTIBLE POWER AN IMPORTANT RESOURCE FOR THE STATE OF FLORIDA?**

A Yes. The interruptible tariffs have been in place for decades. They have been and currently are a valuable resource to TECO and to the state as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that the lights will stay on for the firm customer base. Such interruption often causes production to be shut down resulting in losses for the interruptible customer.

Q **HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?**

A The Commission should not approve any changes that would discourage the continued use of this valuable resource. Rate designs that create instability, such as TECO's proposed rate structure, should be rejected.

Q **WHY IS A STABLE RATE DESIGN IMPORTANT TO MAINTAIN THE VIABILITY OF INTERRUPTIBLE POWER?**

A Interruptible power is not cost free for the participating customer. It may require substantial investment in equipment and modifications to manufacturing operations, the cost of which interruptible customers expect to recover over a period of time through lower rates. Thus, rate stability is an important consideration in the design of interruptible rates. Significant changes in interruptible rates that reduce a customer's expected savings are inequitable to the existing customers as a matter of policy, because such changes increase the risk that the expected benefits will not outweigh the costs.

Further, for some customers, interruptible service is the only viable option. This is particularly the case for firms that produce commodity products, such as phosphate and industrial gases. Electricity is a significant operating cost in producing these products. Firms operating in these industries continue to face increasing global and domestic competition. An arbitrary change in cost allocation policy and drastic rate design changes could further raise their manufacturing costs and seriously hamper the continued operation of these firms.

Q **WHAT CONCERNS DO TECO'S RATE DESIGN PROPOSALS RAISE?**

A TECO's proposals raise several policy concerns. Specifically:

- Should payments to interruptible customers be subject to periodic changes outside of a base rate case?

- Is it reasonable and necessary for TECO to recover the cost of providing interruptible service through the ECCR?
- Is TECO properly valuing interruptible service?
- Is interruptible service the same as DSM?
- Should the interruptible credit be reduced by the customer's monthly load factor?

I address each of these important questions below.

__Subjecting the CCV to Periodic Changes__

Q **DOES TECO'S PROPOSAL TO TRANSFER SCHEDULE IS/SBI CUSTOMERS TO THE GSLM RIDERS SUBJECT THESE CUSTOMERS TO PERIODIC BASE RATE CHANGES?**

A Yes. The CCV is updated in the annual ECCR filings. The most recent update was filed in Docket No. 080002-EG. In that filing, TECO proposed a CCV of $10.91 for the period January through December 2009.[36] Prior years' CCVs have ranged from $3.71 in 2001 to $7.78 in 2007.[37] Thus, unlike firm customers, interruptible rates would be subject to change (up or down).

Q **ARE RETAIL CUSTOMERS THAT PURCHASE FIRM POWER FROM TECO SUBJECT TO BASE RATE CHANGES OUTSIDE OF A BASE RATE CASE?**

A No. Once the Commission sets base rates, they are not changed until the next rate case.

Q **IS IT REASONABLE TO SUBJECT SCHEDULE IS/SBI CUSTOMERS TO PERIODIC BASE RATE CHANGES OUTSIDE A FULL RATE CASE?**

A No. Among the rate design criteria TECO says it has considered in this proceeding are revenue stability and continuity.[38] Subjecting customers to potentially unstable rate designs, by pegging the CCV to ever changing measures of avoided cost, is fundamentally incompatible with these criteria.

Q HOW CAN THIS PROBLEM BE AVOIDED WITHOUT CAUSING HARM TO TECO'S CUSTOMERS?

A The easiest solution is to maintain the current Schedule IS/SBI structure but reset the rate to reflect the increasing value of interruptibility. As with TECO's other rates, no further changes would be made until the next rate case. With rising equipment costs, this more traditional rate-making approach would provide the necessary stability without causing harm to other customers.

Should the Commission prefer the approach that TECO proposes in this case, then an interruptible customer should have the option of locking-in the current CCV for an extended period of time, say five or ten years, at the customer's option. This alternative would also provide a more stable rate design. Further, other customers would not be harmed even if equipment costs were to suddenly (and unexpectedly) decline. This is because, as discussed later, interruptible load has allowed and (if properly nurtured) will continue to allow TECO to defer capacity additions.

<u>Recovery through the ECCR</u>

Q IS IT REASONABLE AND NECESSARY TO RECOVER INTERRUPTIBLE CREDITS FROM SCHEDULE IS/SBI CUSTOMERS THROUGH THE ECCR?

A No. The purpose of cost recovery clauses is to allow more timely recovery of costs outside of a general rate case when the failure to adjust rates would otherwise have an adverse financial impact on the utility. Thus, the costs subject to change in between general rate cases should be:

1. **Material**—that is, the particular expense is large in relation to the utility's overall revenue requirement,

2. **Volatile**—that is, the level of a particular expense is subject to wide fluctuations over a relatively short time-period; and

3. **Beyond the utility's direct control**—that is, a particular expense is subject to the impact of global and domestic commodity markets.

Fuel and purchased power energy costs meet these criteria. These costs account for over 48% of TECO's overall revenue requirements. As the Commission is well-aware, fuel costs reflect volatile changes in commodity costs. And, coal and natural gas prices affected by global markets are largely beyond TECO's direct control.

Q DO THE CAPACITY CREDITS PAID TO INTERRUPTIBLE CUSTOMERS MEET ALL THREE CRITERIA NECESSARY FOR SPECIAL COST RECOVERY TREATMENT?

A No. These payments constitute less than 1% of TECO's overall revenue requirements. Fixing interruptible rates based on the current value of interruptibility is well within TECO's direct control. Further, it would provide greater stability both for interruptible customers and the Company. Rates that fluctuate due to ever changing avoided cost estimates would make the capacity credits unnecessarily volatile.

Value of Interruptibility

Q HAS TECO CALCULATED THE LEVEL OF INTERRUPTIBLE SERVICE CREDIT?

A Yes. TECO filed a cost-effectiveness test in Docket No. 080002-EG that shows that the resulting credit for interruptible customers should be $10.91 per coincident peak (CP) kW.[39]

Q DO YOU AGREE WITH THE $10.91 VALUE AS DETERMINED BY TECO?

A No. The $10.91 CCV is understated for two reasons. First, the analysis assumed zero avoided capacity costs for the period 2008 through 2011. This assumption is based on a further assumption that the capacity avoided by interruptible power would be a 2012 combustion turbine (CT). Second, the analysis is based on the net present value of the costs and benefits of interruptible power with 2008 as the base year. As a consequence, the costs and benefits in 2009 were discounted. The CCV is supposed to be in effect in 2009. Therefore, 2009 should be used as the base year, rather than 2008, and the corresponding 2009 costs and benefits should not be discounted by one year.

Q WHY WOULD USING A 2012 AVOIDED UNIT UNDERSTATE THE VALUE OF INTERRUPTIBILITY?

A TECO's cost-effectiveness analysis assigns *costs* to interruptible service in the form of incentive payments beginning in 2008 and for each year over the model's 25-year time horizon. However, the corresponding *benefits*, which primarily consist of avoided generation capacity costs, do not commence until 2012. In other words, the analysis assumes zero avoided generation capacity *benefits* for the period 2008 through 2011.

Q IS IT REASONABLE TO ASSIGN ZERO VALUE TO DEFERRED GENERATION CAPACITY IN THE YEARS 2008 THROUGH 2011?

A No. The interruptible tariffs have been in existence for decades. Their existence has allowed TECO to avoid building unneeded generation capacity (because capacity additions are based on projected firm loads). It should be noted that TECO is including the cost of five new CTs in its test year revenue requirements. Without interruptible load, TECO could have added six or more CTs. By specifically ignoring the capacity benefits provided by interruptible loads in the past, which continue to accrue benefits in the years 2008 through 2011, TECO's cost-effectiveness analysis understates the CCV.

Q **WHAT CHANGES SHOULD BE MADE TO TECO'S APPLICATION OF THE COST-EFFECTIVENESS MODEL TO MORE APPROPRIATELY MEASURE THE COSTS AND BENEFITS OF INTERRUPTIBLE POWER?**

A First, the base year of the model should be 2009 to recognize that the rates approved in this case will not become effective until May 2009, and the CCV would remain in effect for up to 36 months.

Second, since the incentive payments are principally made to recognize the avoided capacity cost benefits of interruptible service, the model should include avoided generation capacity costs for each year of the model's time horizon. It would be reasonable to set these avoided generation capacity benefits based on the installed cost of the Baytown and Polk CTs that TECO is proposing to include in rate base in this proceeding.

Q **HAVE YOU RE-RUN THE COST-EFFECTIVENESS MODEL WITH THE TWO CHANGES DESCRIBED ABOVE?**

A Yes. **Exhibit ___(JP-19)** is a revised cost-effectiveness analysis, which is based on the same analysis TECO presented in Docket No. 080002-EG, with the two recommended changes. As can be seen, the two changes would result in a CCV of over $13.70/kW, which is 25% higher than the $10.91/kW CCV derived by TECO and much more representative of the value of interruptible power.

Q **YOU PREVIOUSLY STATED THAT THE CCV IS BASED ON ACHIEVING A 1.2 BENEFIT-TO-COST RATIO USING THE RIM TEST. IS THERE ANY ECONOMIC REASON WHY THE CCV NEEDS TO ACHIEVE A 1.2 BENEFIT-TO-COST RATIO?**

A No. Other ratepayers would be no worse off if the CCV were set at full avoided cost (*i.e.*, a 1.0 benefit-to-cost ratio). Interruptible power offsets the need for additional generating capacity, thereby reducing total capacity costs from what they would have otherwise been without the presence of interruptible service.

The obvious analogy is with a fire insurance policy. Even though many years may pass without incident, the homeowner will continue to pay the insurance company to maintain the appropriate coverage. At a minimum, the cost that the system pays for this insurance coverage (in the form of interruptible demand credits) should reflect the avoided cost associated with deferring the installation of new peaking generation capacity on the TECO system. This is the case because peaking capacity is the type of generation that is most likely to be avoided through the continued presence of interruptible load on the utility's system.

Q **HAVE POLICY MAKERS ALSO RECOGNIZED THIS INTRINSIC VALUE OF INTERRUPTIBLE POWER?**

A Yes. Interruptible power provides "insurance" in the event that the utility experiences extreme weather, understates load growth, or sustains forced outages of a major resource. As the FERC has found:

> *61804 **[E]ven a limited right of interruption**, if it enables the Company to keep a customer from imposing demands on the system during peak periods, **gives a Company the ability to control its capacity costs.** Therefore, that customer shares no responsibility for capacity costs under a peak

> responsibility method. [FN145]
>
> It is, thus, the right to interrupt that is critical to the analysis, and not the actual interruptions or even the number or length of such interruptions. If a Company can keep a customer from imposing its load on the system at system peak, as Entergy can do here, then, under the peak responsibility method of cost allocation that Entergy uses, "that customer shares no responsibility for capacity costs...." [FN146]
>
> 75. Second, the distinction that the initial decision draws between "reliability" and "economic" considerations is also unclear. When a utility makes a commitment to serve firm load, it commits to serve that load at all times (absent a force majeure event on the system). When a utility makes a commitment to serve interruptible load, it does not commit to serve that load at all times. **To the contrary, it expressly reserves the right to interrupt (even if there is no force majeure event on its system).** Moreover, when it curtails interruptible load, it does so to protect its service to its firm load. That is, it curtails interruptible load precisely because it has not undertaken to construct or otherwise acquire the necessary facilities to serve interruptible load at all times and most particularly when use of the system is peaking; for firm load, in contrast, it has undertaken to construct or otherwise acquire such facilities.[40]

Q **HAS THE INTRINSIC VALUE OF INTERRUPTIBLE POWER RECENTLY BEEN DEMONSTRATED?**

A Yes. This past September, interruptible customers were curtailed twice, on two consecutive days, so that TECO could provide contingency reserves to assist other utilities in the state.[41]

<u>Interruptible Service is Not the Same as DSM</u>

Q **SHOULD INTERRUPTIBLE SERVICE BE TREATED THE SAME AS DSM PROGRAMS FOR THE PURPOSE OF DESIGNING INTERRUPTIBLE RATES?**

A No. The utility's obligation to serve customers who participate in DSM programs distinguishes DSM programs from interruptible service. A utility that funds a DSM program, such as home insulation, continues to provide firm service to its customers. The capacity and energy savings associated with such programs are merely a substitute for the power and energy sales that have been the traditional services provided by a regulated utility. Thus, DSM programs maintain or enhance the quality of firm service that customers receive.

By contrast, interruptible power is a lower quality of service. The utility does not have an obligation to serve interruptible customers whenever (and without limit) capacity is needed to maintain service to firm load customers. Non-firm customers therefore relinquish their entitlement to use power and energy upon demand in exchange for a lower rate.

Further, as previously explained, interruptible loads are used to satisfy TECO's contingency reserve requirements as determined by the FRCC.

These characteristics clearly distinguish interruptible power from passive DSM programs.

<u>**Load Factor Adjustment**</u>

Q UNDER TECO'S PROPOSAL, WOULD ALL INTERRUPTIBLE CUSTOMERS RECEIVE THE $10.91 PER CP KW CCV?

A No. Under TECO's proposal, the $10.91 per kW CCV would be reduced in proportion to the customer's billing load factor. These credits would, in turn, be further reduced by any applicable metering voltage adjustment. For example, a primary distribution level customer having a maximum kW demand of 5,000 kW at a 70% load factor would have an effective interruptible credit of only $7.48 per kW ($10.91 per CP kW x 70% x 98% to account for the metering voltage adjustment).

Q IS THIS LOAD FACTOR ADJUSTMENT A VALID APPROACH FOR ALLOCATING THE INTERRUPTIBLE CREDITS WITHIN THE IS CLASS?

A No. First, TECO's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that there is a linear relationship between load factor and coincidence factor. However, TECO has provided no evidence of such a linear relationship.

Second, even if such a relationship could be demonstrated, since the amount of interruptible load is based on the average 12CP demand of the IS class, the adjustment should be made relative to the class average load factor or 96%.

Also, recall that the definition of coincidence factor is the ratio of the customer's coincident peak demand (that is, the demand coincident with the one-hour monthly system peak) to the customer's non-coincident peak demand. Thus, the load factor adjustment erroneously implies that the amount of interruptible load is strictly a function of the demand coincident with TECO's one-hour monthly system peak. In reality, interruptions can occur at any time, not just coincident with the system peak or with the on-peak hours. For example, a customer could be planning to operate at his maximum demand but be unable to do so because of a curtailment. If this same customer only operated at a 50% load factor during the month, he would only get credit for half of the interruptible capacity that he is providing to TECO.

If a customer's load factor is sufficiently low in a given month, TECO's proposed adjustment could effectively cause the customer to pay a firm rate for an interruptible service of lower quality. This result could cause interruptible customers to reduce their operations in TECO's service territory or to relocate those operations to other parts of the country.

Q **HOW SHOULD THE MONTHLY CREDIT BE STRUCTURED?**

A The Monthly Credit should reasonably measure the amount of load that TECO is not obligated to serve during an interruption event. When an interruption event occurs, an interruptible customer's operating demand may immediately be reduced to zero. However, reducing existing operating demand to zero is not the only benefit of an interruption. In lieu of an interruption, a customer may have anticipated operating at a higher level of demand. The fact that the customer was prevented from imposing a higher level of demand during an interruption period provides a benefit to the system.

To measure this benefit, it is my recommendation that the amount of interruptible demand subject to credit be determined by establishing each customer's normal operating demand for a defined "base line" period. For example, Southwestern Public Service Company (SPS) uses the following definition of interruptible demand:

> MONTHLY CREDIT
> The customer's Monthly Credit shall be calculated by multiplying the Monthly Credit Rate (MCR) by the lesser of the customer's CIL or the actual Interruptible Demand during the billing month.

The CIL or Contract Interruptible Load is defined as:

> The median of the customer's maximum daily thirty (30) minute integrated kW demands occurring between the hours of 12:00 noon and 8:00 p.m. Monday through Friday, excluding federal holidays, during the period June 1 through September 30 of the prior year, less the Contract Firm Demand, if any. If customer has no history in the prior year or customer anticipates that its CIL for the upcoming year will exceed the prior year's CIL by one hundred (100) kW or more, at customer's request, Company may, in its sole discretion, estimate the CIL. In extraordinary circumstances, Company may calculate CIL using load data from the year one year prior to the year normally used to calculate the CIL, if the customer has shown that, due to extraordinary circumstances, the load

> data that would normally be used to calculate its CIL is less representative of what the customer's load is likely to be in the upcoming year than its load data from the year one year prior to the period normally used.
>
> For existing customers, Company shall calculate the customer's CIL to be used in the upcoming year by December 31st of the then current year. If the Company determines that the customer's CIL to be used in the upcoming year is less than 500 kW, then the Agreement shall terminate at the end of the then current year. If the Company determines that the combined CIL of all existing customers to be used in the upcoming year exceeds 85MW, then those existing customers whose CIL is greater than the prior year's CIL may be required to reduce their CIL (by increasing their Contract Firm Demand) proportionally in order that total CIL does not exceed 85MW.[42]

Thus, SPS does not use load factor as a proxy for the amount of interruptible load.

Q IS THERE ANOTHER ALTERNATIVE TO DETERMINE THE AMOUNT OF INTERRUPTIBLE LOAD?

A Yes. Another alternative would be to directly measure the amount of interruptible demand in real-time. This would require establishing a "normal" operating demand from a past period, such as on the day, week, or month that curtailments occur (excluding the curtailment periods).

Q WHICH OF THESE TWO ALTERNATIVES DO YOU RECOMMEND?

A While the real-time method would be the most accurate, I recommend using the SPS method as described above. This method would be easier to administer.

Q IS THERE ANOTHER REASONABLE ALTERNATIVE APPROACH IF THE COMMISSION REJECTS THE SPS METHOD?

A Yes. In lieu of the two alternatives discussed earlier, the credit could be applied as a reduction to the maximum demand charge as is presently the case. In other words, each customer should receive the same credit per kW of billing demand. Finally, in no event should load factor be used to adjust the amount of the credit unless the load factor is based on the class average load factor, not the 100% load factor that the Company proposes to use.

7. COST RECOVERY CLAUSES

Q IS TECO PROPOSING TO IMPLEMENT A NEW COST RECOVERY CLAUSE?

A Yes. TECO is proposing to add a fifth cost recovery clause, the Transmission Base Rate Adjustment (TBRA). As described by TECO witness, Jeffrey Chronister, the purpose of the TBRA would be to allow TECO to timely recover the costs associated with 230 kV and above transmission projects submitted for FRCC review, which are not already being recovered through base rates or a cost recovery clause.[43]

Q HOW WOULD THE TBRA WORK?

A The details are sketchy because TECO did not provide a written tariff. However, Mr. Chronister states that the TBRA would be similar to the Capacity Cost Recovery (CCR) clause. The Company would seek cost recovery for transmission plant additions that TECO projects will be substantially complete by calculating a revenue requirement using the authorized cost of equity and capital structure. A true up would be made to account for differences between estimated and actual expenditures.

Q HOW WOULD THE TBRA DETERMINE TRANSMISSION PLANT COSTS THAT ARE NOT ALREADY BEING RECOVERED THROUGH BASE RATES OR A COST RECOVERY CLAUSE?

A Assuming the design of the TBRA is similar to the CCR, recovery would include 100% of the costs of all new 230 kV transmission investment related to the specific FRCC-approved projects that are not already in rate base.

Q SHOULD THE PROPOSED TBRA BE IMPLEMENTED?

A No. TECO already has four separate cost recovery clauses that account for over 54% of its total revenue requirements. Adding a fifth clause would only exacerbate the current bias (that favors cost-recovery clauses) and would not provide a balanced regulatory framework. The Commission must balance the interests of ratepayers with the interests of the regulated utility. That balance would be thwarted by yet another new piecemeal rate rider. This is because piecemeal rate riders shift the risks that are normally the responsibility of utility shareholders between rate cases to ratepayers. Ratepayers would see their non-fuel rates rise and fall without a rate case. This represents piecemeal or single-issue ratemaking.

Q **WHAT DO YOU MEAN BY *PIECEMEAL* OR *SINGLE-ISSUE* RATEMAKING?**

A Piecemeal ratemaking would allow a utility to raise rates to reflect changes in certain specified costs, while ignoring potentially offsetting changes in other costs not subject to the rider. For example, the proposed TBRA would allow TECO to reflect changes in certain transmission capital costs. However, these changes would be made in isolation because they would ignore any potentially offsetting rate base reductions due to plant retirements or depreciation. Thus, even if TECO's rate base decreases, TECO would be allowed to increase rates solely based on incremental transmission investment.

Q **WHAT OTHER CONCERNS DO YOU HAVE ABOUT THE TBRA?**

A As previously stated, costs that are subject to recovery outside of a general rate case should be *material*, *volatile,* and *beyond the utility's control.* Transmission investment does not meet any of these criteria. Specifically, the projected $68.1 million of transmission plant additions in 2009 is less than 2% of TECO's rate base. Once a transmission facility commences service, the revenue requirement is fixed and does not vary over time. Further, as a member of the FRCC and as the party responsible for constructing new facilities, TECO has some control over the both the timing and cost.

Q **WOULD THE ABSENCE OF A TBRA PREVENT TECO FROM HAVING A REASONABLE OPPORTUNITY TO RECOVER THE COST OF TRANSMISSION CAPACITY ADDITIONS?**

A No. As TECO sells more energy, base rate revenues will also grow. Thus, TECO will have more revenue with which to recover increasing costs, including future plant additions. Stated differently, transmission plant additions will be offset to some degree by the growth in revenues stemming from growing electricity sales. The offset would be more significant because, as previously discussed, the base rates in this case are being set with an assumption of much slower sales growth during the test year.

Finally, if TECO is unable to earn a reasonable return, then it always has the option of filing a general rate case.

Q **IF ANOTHER PIECEMEAL RATE RIDER IS ADOPTED, WHAT IMPACT SHOULD THIS HAVE IN DETERMINING TECO'S REVENUE REQUIREMENTS IN THIS PROCEEDING?**

A Dollar-for-dollar recovery of costs, with interest, not only reduces regulatory lag but lowers TECO's regulatory risk. Thus, if the piecemeal rate riders are adopted, this lower risk should be considered in determining TECO's authorized return on equity. All other things being equal, adopting the proposed riders should result in a lower authorized return on common equity.

Q **DOES THIS CONCLUDE YOUR DIRECT 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. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

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 request 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 in two Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. 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 list of my appearances since 1994 is attached.

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 and Houston, Texas.

ENDNOTES

[1] Mosaic filed a petition to intervene in this case on November 25, 2008.

[2] *Direct Testimony of Lorraine L Cifuentes*, Exhibit __, (LLC-1) Document No. 6.

[3] TECO's Response to FIPUG First Set of Interrogatories, No. 1.

[4] TECO's Response to FIPUG First Set of Interrogatories, No. 2.

[5] TECO's Response to FIPUG First Set of Interrogatories, No. 2.

[6] *Direct Testimony of Mark J. Hornick* at 15.

[7] *Direct Testimony of Dianne S. Merrill* at 10.

[8] *Id.*

[9] TECO Response to OPC's Third Set of Interrogatories, Interrogatory No. 31.

[10] *Id.*

[11] Source: SNL Financial

[12] TECO Response to OPC's Third Set of Interrogatories, Interrogatory No. 30.

[13] *See,* Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Final Order* issued August 15, 2005 at paragraphs 164 – 170.

[14] Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Proposal for Decision,* issued July 1, 2004 at 92.

[15] *Id,* at 95.

[16] *Id,* at 96.

[17] *See,* Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Final Order* issued August 15, 2005 at paragraphs 169 – 170.

[18] *Id.*

[19] *In the Matter of the Application of PacifiCorp for a Retail Electric Utility Rate Increase of $41.8 Million per Year,* Docket No. 20000-ER-03-198, *Order* issued February 28, 2004 at pp. 30-31.

[20] *Id.*

[21] *Direct Testimony of William R. Ashburn* at 38.

[22] Order No. PSC-92-0002-FOF-EI at 4.

[23] Gulf Power Company, Florida Public Service Commission Docket No. 891345-EI, *Order No. 23573* at 42 (Oct. 3, 1990).

[24] *Order No. PSC-93-0165-FOF-EI* at 74.

[25] *Order No. PSC-05-0945-5-S-EI*; *Order No. PSC-05-0902-S-EI* at 4.

[26] Tampa Electric Company Nineteenth Revised Sheet No.6.090.

[27] 106 FERC ¶61,228, at 14 (emphasis added).

[28] Tampa Electric Company, *Ten Year Site Plan, 2008* at 51.

[29] Docket No. 010949-EI, *Order No. PSC-02-0787-FOF-EI* at 80.

[30] Florida Reliability Coordinating Council, *Handbook*, FRCC Contingency (Operating) Reserve Policy, November 2008.

[31] *Order No. PSC-99-1778-FOF-EI* at 8.

[32] *Id.* at 2.

[33] Docket No. 080002-EG, *Testimony of Howard T. Bryant* at Bates 60.

[34] FERC Docket No. RM06-16-000, Order No. 693 at 102.

[35] 122 FERC P 61167,2008 WL 469319 (FERC).

[36] Docket No. 080002-EG, *Testimony of Howard T. Bryant* at 9.

[37] TECO's Response to FIPUG's POD 20 at Bates 1507.

[38] *Direct Testimony of William J. Ashburn* at 38.

[39] Docket No. 080002-EG, *Testimony of Howard T.* Bryant at 9.

[40] 106 FERC ¶61,228, at 14 (emphasis added).

[41] TECO's Reply to FIPUG Interrogatory No. 38.

[42] Southwestern Public Service Company, *Electric Tariff*, Section No. IV, Sheet No. IV-177.

[43] *Direct Testimony of Jeffrey S. Chronister* at 44.

Appendix A
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
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	
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
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
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

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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
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
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 CENTRAL 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,	12/17/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/17/2006
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	09/07/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006

002312

Appendix A
Testimony Filed in Regulatory Proceedings
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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
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
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)	8/19/2005
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

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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
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

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7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
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
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

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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
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

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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

BY MS. KAUFMAN:

Q Okay. Have you prepared a summary of your testimony?

A I have.

Q And would you please give that?

A I will.

Good morning, Commissioners. My testimony addresses the class cost-of-service study, revenue allocation, interruptible rates, other rate design issues, certain revenue requirements in the proposed transmission base rate adjustment. Since you've heard a lot of discussion mostly on revenue requirement issues, I'm going to focus my summary on the cost-of-service rate design issues.

Tampa Electric's class cost-of-service study is seriously flawed and should be rejected. The interruptible class should not be consolidated either with the GSD or GSLD classes, nor should the credit that TECO proposes vary between rate cases. Further, the interruptible credit must appropriately compensate interruptible customers for the type of service they receive.

The reasons for rejecting the company's cost-of-service study are as follows. First, it improperly allocates production plant costs. The 12CP and 25 percent average demand method would more than triple the amount of production plant costs that are classified to energy or average demand rather than peak demand.

In addition, the environmental and Polk gasifier costs are improperly classified to energy, and, as a consequence, 43 percent of total production plant costs are being classified to energy. That's an inordinate amount.

Third, the 12CP method doesn't reflect TECO's cost system load characteristics.

Regarding the 12CP and 25 percent average demand method, this method has never been approved by you, and for good reason. Power plant components are sized to meet, provide a certain amount of capacity. The company must have sufficient capacity to meet projected firm annual system peak demand. For TECO its firm annual system peaks occur primarily during those hot and humid summer months and a short duration of peak occurs during brief cold snaps in the winter months. The heat and humidity mean that generators and transmission lines and equipment cannot carry as much load during the summer months. Despite scheduling outages during the spring and fall months which reduce available capacity, the company still has lower reserve capacity in the summer months when the peaks occur. These physical realities suggest that all production plant costs should be allocated on a summer or winter peak basis, not 12CP, which assumes that all months are equally important in meeting customer demand throughout the year.

Unlike peak demand, year-round energy is not a determinant of the amount of capacity TECO needs to meet its obligation to serve. As a matter of pure physics, if TECO would only have the amount of capacity needed to serve its year-round energy requirement, it could not provide reliable service.

However, the Commission has historically recognized that some production plant costs are incurred to reflect energy-related considerations. While this issue has been and continues to be extensively debated, recognizing energy-related considerations is what led this Commission to adopt the 12CP and 1/13th average demand method. As shown in my analysis, even this method allocates costs beyond the economic break-even point between baseload and peaking capacity.

Let me elaborate. The concept of a break-even point has previously been recognized by the Commission when it rejected costing methods similar to TECO's proposal in this case such as equivalent peaker. It is an important concept because the break-even line, break-even point is the dividing line between cost causation and cost shifting. Only energy usage up to the break-even point is cost causative. A methodology that goes far beyond the break-even point such as that proposed by TECO in this proceeding is nothing more than cost shifting.

Particularly egregious is the failure to follow the methodology to its complete and logical end. If it's appropriate to shift higher production plant costs to high load factor customers, it's just as appropriate to shift higher fuel costs to low load factor customers. The failure to do so is theoretically inconsistent, it's unsound, it's unfair, it's inequitable. My recommendations stay the course. Apply the 12CP and 1/13th with no special treatment for environmental and the gasifier investment.

TECO has assumed that for costing purposes the interruptible or IS class is receiving firm service. First of all, let's recognize that interruptible customers receive the lowest quality of service. But using this assumption it follows that in determining the cost of serving the IS class, the class's revenues should be restated to the otherwise applicable firm rate. This adjustment recognizes that the costs were interruptible credits incurred to support the interruptible service, and it recognizes that none of these costs should be allocated to the interruptible customers because they are the ones that are providing the capacity for the benefit of the firm customers. Allocating the interruptible credits to interruptible customers as TECO proposes would result in these customers receiving less than the full value for the contingency reserves and other reliability benefits that they have been providing firm customers for decades.

Coupled with my other recommended adjustments to the company's cost-of-service study, the results shown in my

Exhibit JP-10 demonstrate that the interruptible class is providing the highest rate of return, even higher than the GSLD class. And for this reason alone, the company's proposal to consolidate interruptible with GSD and GSLD should be rejected.

Another reason for rejecting class consolidation is the three classes as a whole are quite different. This is shown in my Exhibit JP-5. While Mr. Ashburn notes that there are similarities when you look at monthly bills, he overlooks the differences on a customer basis, and further he totally ignores the primary difference between the three classes, which is that more than half of the interruptible load is served at a --

CHAIRMAN CARTER: Mr. Pollock, I'm sorry.

THE WITNESS: Am I --

CHAIRMAN CARTER: You're at, you're at six minutes, already, sir.

THE WITNESS: I'm sorry.

CHAIRMAN CARTER: Thank you. Ms. Kaufman.

MS. KAUFMAN: The witness is available for cross-examination.

CHAIRMAN CARTER: Okay. Commissioners, why don't I go through the parties first, but I can always come to the bench. Just let me know, we'll do that.

Ms. Christensen.

MS. CHRISTENSEN: TECO. TECO.

CHAIRMAN CARTER: You have no questions for --

MS. CHRISTENSEN: Well, I do. I just didn't know if --

CHAIRMAN CARTER: Well, it's not your witness, so you go ahead. You're recognized.

MS. CHRISTENSEN: Certainly.

CHAIRMAN CARTER: Thank you.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q I just have a few questions. You talk about in your testimony the transmission base rate adjustment mechanism that Tampa Electric has proposed. To your knowledge has any state commission or even this Commission approved such a mechanism?

A Your question was has any state commission or this Commission approved this previously?

Q Yeah. And I can break it down into two questions.

A Yeah. Let me answer the first question. There are circumstances where utilities are allowed to recover transmission costs in between base rate cases. The Commission in Texas, which is a little different situation than exists here because the utilities there are completely unbundled and the utilities, the regulated utilities in Texas only provide delivery of service, so that's a little different situation than exists here. But that is a case where the utilities were allowed to recover increases in transmission investment between rate cases.

As far as this Commission is concerned, I'm not aware that any such clause has been provided, has been approved in past cases.

Q Okay. So let me see if I understand your, your response. Even though Texas has allowed it, allowed some transmission recovery, they don't, they're not talking about a similar mechanism as what Tampa Electric has requested in this case?

A It's hard to say what the mechanism is that the company has requested because, as I explain in my testimony, the details are somewhat sketchy. But the concept is to allow some, some, recover some current recovery of costs, and the Texas transmission cost recovery factor does allow that. It doesn't -- it does so in a way that recognizes the dynamics of ratemaking, which I'm not sure that the company's proposal in this case would, would fully recognize.

Q I'm not sure what you mean by the dynamics of ratemaking.

A And I discuss this in my testimony. The fact of the matter is, is that in between rate cases there's, there are always changes that occur, and one of the biggest changes that occur is that sales grow. And in a growing sales environment, those additional sales generate additional revenues that then defray and offset the incurrence of additional fixed costs.

So what happens is just because the company may incur, let's say, a $100 million investment for transmission, some of those costs, some of the costs of that investment are already recovered in the fact that just the revenues -- the utility growing generates additional revenue that offsets or defrays a portion of the cost. So the utility, the utility doesn't get the full incremental increase associated with the $100 million. It's reduced by the amount of revenue growth. And, further, it's reduced by the amount of depreciation because as we go out beyond the test year plant is depreciated more. Therefore, the rate base is going down. Therefore, the revenue requirement goes down. So there are two offsetting adjustments, one for growth and one for additional depreciation.

Q Okay. And let me ask you this. Currently would you agree that at least 54 percent of the revenue that Tampa Electric collects is already recovered through clauses, through the existing clauses?

A Yes.

Q Okay. And would you agree that this proposed TBRA mechanism would shift additional risk from shareholders to ratepayers for which they're already getting compensated through base rates for?

A That would be my view, that any time you shift cost recovery from base rates to adjustment clauses that get basically trued up dollar for dollar every year, that's a pretty significant reduction in the regulatory risk of the utility.

MS. CHRISTENSEN: Okay. No further questions.

CHAIRMAN CARTER: Thank you.

Ms. Bradley.

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Okay. Now this is not one that you guys are jointly sponsoring; right? This is a separate -- okay. Mr. Wright.

MR. WRIGHT: I have no, I have no questions, Mr. Chairman. Thank you.

CHAIRMAN CARTER: Okay. From the company.

MR. WILLIS: No questions.

CHAIRMAN CARTER: Okay. Commissioners? Commissioner Argenziano, you're recognized.

COMMISSIONER ARGENZIANO: Thank you.

Mr. Pollock, you are opposed, let me find the right place, to the incentive -- where am I? Oh, incentive compensation. And could you explain why and, why you're opposed to that and I guess opposed to the executives, the CFO and the President receiving that compensation?

THE WITNESS: Yeah. I don't think we're opposed to that per se. But I think what our testimony is and our recommendation is that any incentive compensation where the payout is geared to the financial performance of either Tampa Electric or TECO Energy is clearly for the benefit of the shareholders, increasing shareholder value. It's not clear and I don't think the company has demonstrated that those costs are for ratepayer benefits and provide direct benefits to actual ratepayers.

COMMISSIONER ARGENZIANO: So the compensation part of that being, being related to enhancing the value of the parent company and not the -- there's no benefit to the ratepayer is what you're saying.

THE WITNESS: That's our position. Yes.

COMMISSIONER ARGENZIANO: Okay. And do you recall, I can't find the page, the compensation to the executive officers for the incentive?

THE WITNESS: Yes. Yes. That's on Page 13.

COMMISSIONER ARGENZIANO: Which was how much? Is that, is that correct, the parent -- let's see. The president and CFO received approximately $1.5 million in incentive compensation including stock awards worth approximately $810,000 and nonequity and incentive payments for approximately $690,000 for 2007?

THE WITNESS: Yes. That's information we got, we obtained publicly.

COMMISSIONER ARGENZIANO: And it is your belief that that, that compensation is really benefiting the parent company?

THE WITNESS: Well, that is the compensation that the officers received. It's a little different issue than how much should the rates of Tampa Electric Company, which include some incentive compensation, how much those rates should be adjusted to reflect that or not.

COMMISSIONER ARGENZIANO: And I wonder if you could talk to me more about the cost sifting. I need a better understanding of the cost shifting.

THE WITNESS: You mean on the cost allocation stuff?

COMMISSIONER ARGENZIANO: Yes.

THE WITNESS: Yes. Basically what -- if you look at the utility, the utility is designed to provide capacity to meet the peak demand.

And if I could use a, kind of a bang for the buck example. If I'm the guy that's got to cross a proverbial stream, and I'm about 5'6" tall and the proverbial stream has an average depth of five feet, but in the middle the depth is about 12 feet and I can't swim, guess what's going to happen? I'm not going to make it.

COMMISSIONER ARGENZIANO: You're going to get your hair wet.

THE WITNESS: Yes. Well, I'm going to do more than that. I might not make it to the other side. And, of course, I'm obligated to do that and a utility is obligated to provide service to its customers as well. And so they have to provide capacity to meet those, those summer -- as I said, TECO is a summer peak utility with a secondary winter peak.

When you allocate costs away from the demands that cause the utility to incur these costs and look at factors such as demands in the spring and fall months like the 12CP method or you look at energy which is another way of saying average demand, that's the average five foot depth of that stream that we just tried to cross unsuccessfully, then what you're really doing is you're shifting costs away from the things that really caused the capacity to be incurred on to something else and that's the cost shifting issue. I describe it a little differently in the concept of the break-even point, but that's essentially what the cost shift is.

COMMISSIONER ARGENZIANO: Okay. Thank you.

THE WITNESS: Thank you.

CHAIRMAN CARTER: Anything further from the bench? Redirect?

MS. KAUFMAN: I just have one redirect follow-up on Commissioner Argenziano's question about the cost shifting.

REDIRECT EXAMINATION

BY MS. KAUFMAN:

Q Can you explain how Tampa Electric's proposed methodology inappropriately shifts costs on to the interruptible class?

A Certainly. And this again kind of relates to two factors of their cost study. One is the increase from 1/13th or roughly 8 percent to 25 percent on the average demand and allocating all production plant costs. That's the first level of shift.

The second level of shift is then taking the environmental equipment and the gasifier and allocating entirely on an average demand basis, when we all know that those components are necessary for the plants to operate and provide the capacity.

MS. KAUFMAN: Thank you, Mr. Chairman.

CHAIRMAN CARTER: Thank you.

Exhibit Numbers -- Commissioners, in your records -- 55 through 73, I believe it is. Help me. Yes. 73. And Exhibit 124. Any objections? Without objection, show it done.

(Exhibits 55 through 73 and Exhibit 124 admitted into the record.)

Anything further for this witness, staff? Commissioners? You may be excused.

THE WITNESS: Short and sweet. Thank you very much.

CHAIRMAN CARTER: Okay. Let's do this while I'm checking these exhibits. I think we're making progress, Commissioners. And since we're making progress, I want to try to reward good behavior. And we said we were going to do lunch from 11:30 to 12:45. We'll just go now and be back at 12:45.

We're on lunch.

(Recess taken.)

(Transcript continues in sequence with Volume 15.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 30th day of January, 2009.

Linda Boles

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