BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : **DOCKET NO. 990325-EI**

Petition of Gulf Power Company to determine need for proposed electrical power plant in Bay County.

VOLUME 2

Pages 125 through 243

PROCEEDINGS: **HEARING**

BEFORE: CHAIRMAN JOE GARCIA
COMMISSIONER J. TERRY DEASON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER JULIA L. JOHNSON
COMMISSIONER E. LEON JACOBS, JR.

DATE: **Monday, June 7, 1999**

TIME: Commenced at 10:35 a.m.
Concluded at 3:45 p.m.

PLACE: Betty Easley Conference Center
Room 152
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: KIMBERLY K. BERENS, CSR, RPR
FPSC Commission Reporter
H. RUTHE POTAMI, CSR, RPR
FPSC Commission Reporter

APPEARANCES: (As heretofore mentioned.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(Transcript continues from Volume 1.)

CHAIRMAN GARCIA: I think you made us recess so why don't you go ahead.

MS. JAYE: Thank you, Mr. Chairman.

WILLIAM F. POPE

resumed the stand as a witness on behalf of Gulf Power Company and, having been previously sworn, testified as follows:

CROSS EXAMINATION CONTINUED

BY MS. JAYE:

Q Mr. Pope, if you would please, refer to Staff's Confidential Composite Exhibit starting on Page 2. This is the confidential response to Staff's Interrogatory No. 1 which Gulf calculated the cost-effectiveness of Smith Unit 3 versus the RFP projects. Looking at this particular page, could you tell me what the column entitled "Transmission Grid & Connection Accumulated Present Value" represents? It will be the fourth -- the column fourth from the right.

A This column is in all the spreadsheets provided under this confidential agreement. What that is to represent is the cost differential of transmission capital cost -- the capital cost of transmission improvements as compared to the Smith Unit 3 project for all of the alternatives.

Q Mr. Pope, did you perform any of the analyses of transmission costs which are shown in these columns?

A No, I did not personally do them. No.

Q Do you know who did?

A Yes. It was performed by Southern Company Service's transmission planning.

Q Can you explain why the cost shown in the columns are what they are for each of the respondents and for Smith Unit 3?

A Why they are what they are?

Q Yes. Why the number shown there is the same?

A On Page 2?

Q Yes, sir. It would be the same for all of them.

A Why --

Q I'm trying hard not to even mention the number here.

A I understand, but --

Q The same number is shown for Smith Unit 3 and all of the RFP respondents and I was trying to ask you --

CHAIRMAN GARCIA: Grace, where are you reading from?

MS. JAYE: This is on Page 2 of the confidential information.

CHAIRMAN GARCIA: Okay.

WITNESS POPE: I believe you'll have to ask Ms. Burke those specific questions.

MR. MELSON: Commissioner, my concern is, looking at my copy, the numbers in the column on this sheet for Smith Unit 3 are different from the numbers in the column of the same title to the other respondents.

MS. JAYE: I stand corrected. They are different.

MR. MELSON: I guess I'm misunderstanding the question.

WITNESS POPE: That makes a little more sense. Would you repeat the question?

Q **(By Ms. Jaye)** Let me see if I can phrase it in a different way.

A Okay.

Q Comparing Smith Unit 3 with the other units as relates to this column, Transmission Grid & Connection, how do you explain the difference in the numbers?

A Okay. The differences in the numbers, when you compare Smith Unit 3 with all of the respondent spreadsheets, is the numbers in that particular column represent the differential in revenue requirements -- annual revenue requirements, between the transmission cost for Smith Unit 3 and those of that particular respondent's alternative.

Q This would be the incremental difference?

A Incremental difference.

Q Okay. And showing this difference between the transmission costs of the RFP respondents and the Smith Unit 3, why did Southern Company Services -- or perhaps you don't know -- if you could, indicate which witness may be best to ask this -- why did Southern Company Services not use the actual cost?

A I really don't know why. Ms. Burke may be able to shed some light on that.

Q Continuing to look at these sets of pages, could you explain what the column entitled "Transmission Losses Accumulated Present Value" represents?

A Yes. With all alternatives, the location of the generation carries with it different impacts on the transmission system. That column represents the cost, so to speak, for providing losses to the system from the various alternatives. Let me give you just a brief example.

A generator located at Smith plant has a positive benefit to the transmission losses because it lowers losses. There is a cost associated with replacing those kilowatt-hours if that unit weren't there. Likewise, a unit located in Mobile, Alabama, would have a different set of impacts on the losses. That column represents the dollar -- annual dollars of benefit to the transmission system from the replacement cost of those losses.

Q Looking again at that same column, do the parenthesis that are around the numbers in the column indicate the transmission losses were negative?

A Compared to the base case, yes. They actually went down. Therefore, there was a benefit. The negative, or the parenthesis, means a positive benefit.

Q Looking at this table then in this particular response, it appears that all RFP projects, as well as Smith Unit 3, incurred negative losses. Would you please discuss the primary drivers behind the differences in transmission losses for each one of the projects, and why each project would appear to benefit Southern Company's system from the standpoint of reducing the transmission losses?

A The location of the generator does make a difference to the transmission system. As you pointed out, all of the RFP responses and Smith 3 had positive benefits from a loss standpoint on the Southern electric system. Primarily, and this goes with all of the responses at Smith 3, the location of those generators reduced the losses on the Southern transmission system. That -- to some more than others. Okay. But that's the benefit. That's the effect. It reduced the losses to the Southern electric system, therefore, we assessed the benefit to them.

Q Mr. Pope, would you please explain what comprises Southern Company's, quote, "base case generation expansion plan"?

A I believe Ms. Burke would be better to answer that.

Q Referring back again to Page 2 of the confidentiality that we've been looking at, is the cost of the base case generic expansion plan contained in the column entitled "Base Case Utility Cost"? It would be the seventh column in from the left.

A I believe Ms. Burke would be better to answer those questions.

Q Mr. Pope, as a layman, are you generally familiar with the provision of Section 403.519 Florida Statues that requires a proposed unit must be the, quote, "most cost-effective alternative available"?

A Yes, I am.

Q Is Gulf justifying the proposed Smith Unit 3 as the most cost-effective alternative available to Gulf or to Southern Company?

A To Gulf, yes.

Q Referring again to Page 2, following with the confidential information, does the capital and O&M cost columns on these pages portray the incremental cost of the new unit addition?

A I believe Ms. Burke needs to answer that one too. I want to say, yes, but she's the one that needs to answer that.

Q Continuing on the same page, do the columns entitled, "Base Case Utility Cost and Proposal Utility Cost," refer to the total system revenue requirements associated with the entire Southern Company system, including all fuel impacts?

A Ms. Burke needs to answer that question also.

Q How can cost-effectiveness to Gulf for this unit addition be determined when the cost-effective analysis was performed on a Southern Company system basis?

A Ms. Burke needs to answer that.

Q In your opinion, can Smith Unit 3 possibly be cost-effective to Southern as a whole, but not to Gulf specifically?

A Please repeat that. I don't believe I'm the witness for that, but I will -- ask it again.

Q In your opinion, could Smith Unit 3 possibly be cost-effective to Southern as a whole, but not to Gulf specifically?

A I think Mr. Howell needs to answer that one.

Q I ask you to turn to Pages 19 through 24 in the composite exhibit identified as Exhibit No. 7. These are Gulf's responses to Staff's Interrogatories 21 through 25, and Staff's Request for Production of Documents, 17 through 20. Those are located on Page 33 to 43. Looking at those pages, were Gulf Power's responses to Staff's Interrogatories 21 through 25 and Staff's Production of Documents request 17 through 20 prepared under your supervision or direction?

A I sponsored them in response to the interrogatories, yes.

Q Could you summarize how Gulf Power identified the cost to comply with the applicable federal, state and local environmental mandates for Smith Unit 3?

A The cost estimate used in the Smith evaluation contained the environmental compliance cost for all known and expected laws and regulations -- environmental regulations. And in the area of air -- compliance -- air emissions compliance, we included the cost of selected catalytic reduction, which is actually a higher cost alternative than the chosen strategy of NOX offsets.

So, in that light, all of the environmental cost -- compliance costs are included, including a little premium, a little more conservative estimate in the air emissions.

Q Would that result in the compliance cost identified in Gulf's response to Staff's Interrogatories 23 and 24 being a little on the high side?

A Yes.

Q And if you would, turn to Page 12 of the composite exhibit identified as Exhibit 7. This is Gulf's response to Staff's Interrogatory No. 8. Was Gulf Power's response to this interrogatory prepared under your supervision or direction?

A Yes.

Q Can you provide the most recent information with respect to Gulf Power's efforts to provide natural gas supply to Smith Unit 3?

A Yes. I believe we're planning on doing that.

Q I understand that there is an agreement reached for transportation. How about for the commodity itself? Has there been an agreement reached?

A No.

Q Turning over now to Pages 13 through 14 of the composite exhibit, which is Gulf Power Company's Responses to Staff's Interrogatories 16 and 17. Could you briefly summarize the reasons for the differences in natural gas price forecasts among the several self-build alternatives, specifically with these that appear on Page 13?

A Are you speaking about the commodity price basis --

Q Yes.

A -- on the RFP respondents A, B and C?

Q Of the self-build options of Smith, Daniel, and Mulat Tower?

A Okay. And you're talking about the commodity price adjustment?

Q Yes.

A Commodity price adjustment is factored in because of differences in variable transportation -- variable O&M and differences in locations of where delivery points are from what the basis is. The Daniel Project, let's take that as an example, is sitting basically right on top of the delivery point for natural gas, whereas, Smith and the Mulat Tower are not. In fact, the Smith assumption is on a delivery point in Alabama with very low differential pricing between the delivery -- the assumed basis point and that point, whereas, the Mulat Tower is a pipeline -- separate pipeline company in the Pensacola area. Those carry different adjustments to them because of those differences.

Q Mr. Pope, you indicated earlier that a supplier for the commodity of natural gas has not yet been chosen; no contract has been signed. What was the capacity cost and commodity cost used in calculating the cost-effective analysis then?

A For the RFP?

Q I'm sorry. For Smith Unit 3?

A In the RFP or the initial self-build?

Q Just going now looking at the Smith Unit 3, leaving aside now all the RFPs and self-build options.

A I understand, but it depends on if it's the part that Ms. Burke is testifying to, that the gas assumptions in those vintage of analysis or if it's in the initial self-build.

Q This would be in the initial screening?

A The initial screening, it was a gas commodity price being adjusted from Mobile Bay to the Atmore area. Remember, the initial self-build called for construction of a pipeline from the Atmore area and that was the basis for the commodity price to that point.

Q Mr. Pope, to your knowledge, is there a time frame for choosing a supplier of natural gas commodity to the Smith Unit 3?

A I'm not aware of a time line on that, no.

MS. JAYE: We have no further questions.

COMMISSIONER DEASON: Commissioners? Redirect? Sorry.

COMMISSIONER JACOBS: We were going to hold on. They were going to go ahead and ask some questions on redirect.

COMMISSIONER DEASON: We'll cover that on redirect and then if you need to follow up with some questions, obviously, we'll do that at that time.

REDIRECT EXAMINATION

BY MR. MELSON:

Q Mr. Pope, staying for a minute on Page 13 of Exhibit 7, which is the answer to Interrogatory No. 16, I believe there was a clarification of this interrogatory answer that was made during the deposition of Ms. Burke relating to the identification of Respondents A and C. Can you tell us what change ought to be made on Page 13 here?

A Yes. I apologize. The interrogatory response mixed and swapped two of the respondents. Let me clarify that. That when this interrogatory response refers to Respondent A, those figures to the right actually correspond to Respondent C. Likewise, if you look at the interrogatory response referring to Respondent C, those figures to the right there actually correspond to Respondent A. So those need to be swapped as far as either title or figures.

Q Let me follow up. There were a few questions about reserve margin. Could you turn to your Exhibit WFP-2? It's been identified as hearing Exhibit No. 6. It was the attachment to your supplemental testimony.

A Okay.

Q There were some questions about the difference between 15% reserve margin and a 13.5% reserve margin on a Southern Company basis. What does this exhibit reflect about the actual percent reserve margin Gulf would have on its system following the installation of Smith Unit 3?

A According to schedules for WFP-2, the reserves beginning in 2002, with the addition of Smith Unit 3, are well above the 13.5% -- or actually the Gulf 12.6%, according to the 13.5% Southern system reserves, until the year 2006.

If the reserve margin -- referring back to the question about Peninsular Florida. If the reserve margin were 15% on a Southern system basis that would translate or calculate to a 14.1% Gulf reserve. If you'll look at the table, the reserves would be above or equal to that through the year 2005 if the reserve was 15%. So, essentially, we're above the reserve margin target from 2002 on into 2005 and 2006.

COMMISSIONER CLARK: What does the minus 19 mean for 2005? Does that mean you're losing a contract to purchase power?

WITNESS POPE: That's correct. We currently have a cogeneration -- negotiated cogeneration contract for 19 megawatts that expires May 31st of 2005.

Q **(By Mr. Melson)** Let me go back for a minute to the series of questions you had about backup fuel, and I guess a question Commissioner Jacobs asked at one point -- and I may hop around a little bit here. Commissioner Jacobs was asking for a screening analysis that would show how the Southern system generation operated before and after an outage of Smith Unit 3 due to a gas supply interruption. Do you recall that request?

A Yes, I do.

Q Would there be any difference in the way the Southern system operated, whether that outage of Smith 3 was due to gas supply interruption or was due to any other type of forced outage that the unit might experience?

A No. I believe one of the important parts to remember here is that -- and this is why I was a little bit confusing at the time, and I apologize.

But whether a unit is forced out because of a boiler or turbine outage or whether it's a natural gas supply, the unit is out. And we currently already plan for expected probable forced outage rates. We have an assumption of this unit being forced out because of boiler or turbine outages which forces the whole unit off. A turbine outage could take the whole unit off. There's an expectation of that.

The expectation of those things that we already cover in our generation reserve margin and those criteria, in my opinion, would exceed by far the occurrence of a natural gas pipeline interruption. So, in that light, we already can -- we already evaluate the effects of unit outages in what we already do with regard to gas interruptions.

Q And I believe Mr. Moore's Exhibit RCM-1, which was identified as Exhibit 2, in fact, shows a 3.4% equivalent forced outage rate for Smith Unit 3. Are you familiar with that number?

A That is correct.

Q And based on an 8760-hour year, would you agree that that translates to 297 hours if the unit is modeled as forced out in all of the reliability and economic analyses that are done based on the unit?

A Subject to doing the math, yes, I will agree with that.

Q So you'll accept subject to check?

A Right. I trust your math.

Q Thank you. Would you like to borrow my calculator?

A I've got one over here somewhere.

Q It's better coming from the witness.

A 297.84 hours.

COMMISSIONER CLARK: That's per year?

MR. MELSON: Per year.

WITNESS POPE: Per year. On average.

Q **(By Mr. Melson)** So on average, if the combination of turbine outages, gas supply interruptions, whatever reason there might be for the outages, was less than 298 hours a year, the economics of those outages have already been captured in the analysis that's been done for this need certification; is that correct?

A That's correct.

Q How do you -- is the way that Gulf would expect to cover a forced outage due to a gas supply interruption any different from the way it would expect to cover a forced outage due, for example, to a turbine outage?

A No, no different.

Q And how would you normally -- you may have already testified to this, but could you summarize again how you would expect that type of outage to be covered?

A From a generation planning aspect, reserve margins are -- the reserve margin criteria is designed to carry you from a capacity resource aspect to cover things such as forced outages, abnormal weather conditions and load forecast error. In combination with that, the transmission system is also planned under a criteria of loss of a unit and any transmission element, which could be a line. In combination, these two provide reliability on the system where this unit, for whatever reason, if it's outage, power would continue to flow over the transmission system from other units, other generating units, that are planned for in the generation planning side of it to cover the units -- the customer's power needs. So in combination, all facets of reliability are covered under whether it would be a boiler outage or a natural gas pipeline interruption or a commodity interruption.

COMMISSIONER CLARK: Your answer suggests to me that, going back to Commissioner Deason's question, that there is no reason to have any fuel switching at any facility. Is that what your testimony is?

WITNESS POPE: For this particular case, yes.

COMMISSIONER CLARK: That's not what I asked you. For any facility, the logic of what you're presenting to us suggests to me that you would not have any fuel switching capability for any type of plant.

WITNESS POPE: That's correct.

COMMISSIONER JACOBS: It assumes the system reserve, correct; the Southern Company system reserve?

WITNESS POPE: We're planning to that system reserve, yes.

COMMISSIONER CLARK: Is that assumption only valid if you have good fuel diversity on your entire system?

WITNESS POPE: No.

COMMISSIONER CLARK: So why, as a Commission, should we ever care if there's fuel switching capability? Is it your testimony that it's not something we should be concerned with?

WITNESS POPE: There may be reasons that you would be concerned, but I'm just saying that we're planning both from a generation planning criteria and transmission planning criteria in combination to where that is not a problem and diversity of fuel --

COMMISSIONER CLARK: Why is it not a problem?

WITNESS POPE: -- is a benefit, but I don't think it's one of the things that it depends on. I can't -- I just don't want to answer for somebody in Gainesville, Florida or Florida Power & Light or for other circumstances. I'm just saying that from everything we've done and what we're -- what the Southern electric system -- and it's a benefit of being a part of a large system. We can draw on that large system, whereas, in some cases some others can't. I don't want to be thinking -- let you think that I'm answering for every case, but I'm saying that we plan on the Southern electric system and because of Southern electric system and its large size and some of the benefits of being that large and having multiple interconnections, we can do this without a problem.

COMMISSIONER CLARK: Is it because of your fuel diversity and how you're interconnected that fuel switching capability at any particular plant is not necessary?

WITNESS POPE: It's more of interconnections than it is fuel diversity. I believe our type of fuel, being coal, predominantly coal, almost all coal, is a resource that is not easily interruptible, and that gives you a tremendous benefit from those units being on line from a fuel source. They also carry, as every other unit on the Southern electric system and others throughout the United States -- have a forced outage rate, but we plan for that also.

COMMISSIONER CLARK: Let me ask you it a different way. If every unit at Smith were gas-fired and it was that capacity of each was its present capacity, would your answer be different with respect to fuel switching? Would you feel you needed to have the capability to switch fuel if you had an interruption of natural gas supply to that site?

WITNESS POPE: I would have to say yes.

COMMISSIONER CLARK: Okay. Mr. Pope, I take it -- what I surmise from your answer is that the reason you really don't need fuel switching units is because you have diversity on your system and your system is well interconnected?

WITNESS POPE: That's correct. Yes, ma'am.

Q **(By Mr. Melson)** And Mr. Pope, you were asked some questions about your answers to Interrogatories 32 through 35 that are part of Staff's Exhibit 7. And I don't think you need to turn to them in particular. They deal in general with the backup fuel issue. Were there some environmental licensing concerns, environmental licensing timetable concerns, associated with the provision of backup fuel at Smith?

A That's correct. And that's partially in the cost figures I was asked about earlier. But, it's important to note that if the company were required to provide a backup fuel, No. 2 oil, for instance, we'd also be required to go back and restart the environmental permitting process because -- and we'd also have to abandon the NOX offset, because you can't achieve even the hour-by-hour emissions rate of the unit, the combined cycle unit, with oil firing. There would be some assumptions that would have to be made in the environmental process that would dictate we go back to the selective catalytic reduction alternative, which is a more expensive alternative.

But more importantly, is that it delays the project at least a year because of re -- having to go back and restart the process of the environmental permitting and modeling those emissions and getting those emissions included in the application, which we did file this morning. So there's a year's delay.

And on top of that, there's power that we would have to, for a year or so, secure at whatever cost, which we expect to be very expensive, to make up for that year delay.

But moreover, it wipes out the positive benefits of the NOX offset. That on a site basis, a total site basis, with a combination of doing some things to Smith 1 to reduce their NOX emissions, and adding Smith Unit 3, no longer can we say that the site would have a net air emission reduction for NOX.

COMMISSIONER CLARK: Why not?

WITNESS POPE: Because you don't have enough offsets of Smith 1 with oil firing and the higher emissions of oil firing. You don't have that benefit of NOX -- the NOX emissions out of the Smith 3 unit.

COMMISSIONER CLARK: Maybe I misunderstood. Which site would you add the switching to? Wouldn't it be the natural gas?

WITNESS POPE: Excuse me?

COMMISSIONER CLARK: Maybe I misunderstood you.

WITNESS POPE: The fuel switching would be to Smith 3 only.

COMMISSIONER CLARK: Which is the natural gas.

WITNESS POPE: Which is the natural gas unit. And even though that unit would only be expected in our estimation to use that oil source very rarely, the potential -- the maximum potential, which is what you file in your permit and what you're permitted for and what the emissions that they make you comply with, is what they call the maximum potential, which could be many, many, many, more hours than what is really expected from that unit.

COMMISSIONER CLARK: And that would offset the improvements you're making to 1 and 2?

WITNESS POPE: To Unit 1.

COMMISSIONER CLARK: To Unit 1.

WITNESS POPE: Yes. And there are -- currently under the strategy of natural gas on there is the benefit of a net overall reduction in NOX emissions from Smith 2 that don't go forward if you had oil backup, plus the time of delay.

Q **(By Mr. Melson)** And finally, Mr. Pope, Interrogatory 32 discusses fuel supply strategy for the Smith unit. To the extent you've testified this morning about the entry into a firm gas transportation contract and testified that there is no specific time table for securing the commodity, should we read that interrogatory in light of your further explanation today?

A I would say, yes. At the time it was answered we did not have that firm natural gas transportation agreement in hand and efforts are still going forward to further work on other aspects of the natural gas supply. But transmission -- excuse me. Transportation is by far the most critical in our opinion as far as firmness of the supply fuel to Smith.

MR. MELSON: That was all I had.

COMMISSIONER DEASON: Commissioner Jacobs, do you have anything to follow up?

COMMISSIONER JACOBS: No.

COMMISSIONER DEASON: Okay. Exhibits.

MR. MELSON: Gulf moves Exhibits 5 and 6.

COMMISSIONER DEASON: Without objection, show Exhibits 5 and 6 admitted.

(Exhibits 5 and 6 received in evidence.)

COMMISSIONER DEASON: Staff.

MS. JAYE: Staff would like to go ahead and move Exhibits 7 and 8.

COMMISSIONER DEASON: Let me ask, in reference to Exhibit 8, you're wanting that entire confidential exhibit admitted?

MS. JAYE: Yes, sir.

COMMISSIONER DEASON: Without objection, show then Exhibits 7 and 8 admitted.

(Exhibits 7 and 8 received in evidence.)

COMMISSIONER DEASON: Thank you, Mr. Pope. You're excused.

WITNESS POPE: Thank you.

MR. MELSON: Gulf calls Maria Burke.

MARIA JEFFERS BURKE

was called as a witness on behalf of Gulf Power Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MELSON:

Q Ms. Burke, state your name and address?

A My name is Maria Jeffers Burke. I work at 1600 North 18th Street in Birmingham.

Q And who is your employer and what is your job title?

A I work with Southern Company Services. I'm a project manager in the Generation and Planning and Development Department.

Q And have you prefiled in this docket 12 pages of direct testimony?

A Yes.

Q And have you also filed three pages of supplemental testimony?

A Yes.

Q And does the supplemental testimony essentially update your direct to reflect the increase in the maximum output of the proposed Smith Unit 3?

A Yes, it does.

Q And with the updates, if I were to ask you the same questions today that are contained in your Direct and Supplemental Testimony, would your answers be the same?

A Yes, they would.

MR. MELSON: Commissioner Deason, I ask that those Direct and Supplemental Testimony be inserted into the record as though read.

COMMISSIONER DEASON: Without objection, it shall be so inserted.

Q **(By Mr. Melson)** Ms. Burke, did you have two exhibits attached to your direct testimony identified as MJB-1 and MJB-2?

A Yes, I did.

Q And were those prepared by you or under your direction and supervision?

A Yes, they were.

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

A No.

MR. MELSON: Mr. Chairman, I ask that those be -- MJB-1 and 2 be identified as Composite Exhibit 9.

COMMISSIONER DEASON: It will be so identified.

(Composite Exhibit 9 marked for

identification.)

Q **(By Mr. Melson)** And did you also have an exhibit, MJB-3, which was attached to your Supplemental Testimony?

A Yes, I did.

Q And does that essentially revise and update one of the schedules that have been attached to your Direct?

A Yes, it does.

MR. MELSON: Mr. Chairman, I ask that MJB-3 be identified as Exhibit 10.

COMMISSIONER DEASON: It will be so identified.

(Exhibit 10 marked for identification.)

Q **(By Mr. Melson)** And finally, Ms. Burke, are you sponsoring Chapter 8 and Appendix E of the Need Study that's previously been identified as Exhibit 1?

A Yes, I am.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
Maria Jeffers Burke
Docket No. 990325-EI
Date Filed: April 5, 1999

Q. Please state your name, business address and occupation.

A. My name is Maria Jeffers Burke and my address is Southern Company Services, 600 North 18^{th} Street, Birmingham, Alabama 35202. I am Project Manager in the Generation Planning and Development Department of Southern Company Services (SCS). I am currently responsible for supply side evaluations.

Q. Please describe your educational background and experience.

A. I graduated from Auburn University in August 1986 with a Bachelor of Science degree in Chemical Engineering, and I am currently completing graduate work toward a Masters in Business Administration from Samford University. In 1986, I began my career with the Southern Company at a research facility in Wilsonville, Alabama as a process engineer, and then as the environmental engineer. I continued my environmental permitting work with Southern Electric International in

1990, helping to develop independent power projects both domestically and internationally. I joined the System Planning Department of SCS in November 1992 and spent the next six years in various engineering and supervisory positions. I have been involved in bid evaluation since December 1996.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have an exhibit consisting of 2 schedules to which I will refer. This exhibit was prepared under my supervision and direction. I am also sponsoring Section 8 and Appendix E of the Need Study filed in this docket.

Counsel: We ask that Ms. Burke's Schedules 1 and 2 be marked for identification as Exhibit ______ (MJB-1).

Q. Ms. Burke, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the process employed by SCS in issuing the Gulf Power Request for Proposals (RFP), in receiving responses, in evaluating the offers and in comparing those offers to self-build options.

Q. Please describe your role as it relates to solicitations for capacity resources made on behalf of the Southern companies.

A. In my current position, I am responsible for the evaluation of both short-term and long-term supply side offers for the Southern operating companies. This analysis includes selecting an appropriate production cost modeling tool, verifying the assumptions used in the analysis, preparing the final rankings, and checking all numbers used in the evaluation. However, my responsibilities usually begin earlier in the process, understanding the appropriate regulatory environment and drafting the RFP document for internal review.

Q. What solicitations have you been involved in prior to the one performed on behalf of Gulf Power Company seeking alternatives for their Smith Unit 3?

A. Since assuming responsibility for supply-side evaluations in December 1996, I have been involved in two other solicitations: a Southern system solicitation issued in March 1997 for short-term needs, and an informal market test for Alabama Power. As a result of these solicitations, Southern became concerned that large amounts of relatively inexpensive purchased power were not going to be available much longer, and that the market would soon begin to extract a premium for capacity.

Q. What role did you play in the Gulf Power solicitation?

A. For the Gulf Power solicitation, I was directly involved in the early stages of the solicitation, helping Gulf Power Company draft and issue the RFP document. After the proposals were received from those that responded to the RFP, I was responsible for distributing copies of the proposals within the evaluation team, conducting the generation cost analysis of the proposals, and completing a relative ranking for the proposals. I was also responsible for the comparison of Gulf Power's self-build alternative to the proposals.

Q. How was the RFP distributed?

A. As a normal course of business, SCS maintains a mailing list of developers who are active in the Southeastern United States. This list was updated for Gulf Power Company's RFP and used by SCS to issue the RFP on behalf of Gulf Power Company. The original distribution of the RFP on August 21, 1998 included approximately 100 potential respondents.

Additionally, Gulf Power Company published a notice in appropriate local and statewide newspapers and at least one national trade journal. Gulf Power's objective was to attract any interested developers who may not have been on Southern's original distribution list.

Q. How many proposals were received?

A. On October 16,1998, SCS received, on behalf of Gulf Power, four offers from three separate respondents. The proposals were of various terms and MW sizes, but all offers were in the form of new generating facilities:

- A combined cycle unit in Hardee County, FL
- A combustion turbine facility in Holmes County, FL
- A combined cycle unit in Holmes County, FL
- A family of cogeneration facilities in Mobile, AL and in Santa Rosa County, FL

Q. What would you regard as your overall objective in performing the analysis of the alternatives proposed as they are compared to Gulf Power Company's self-build option?

A. It is my responsibility to ensure that Gulf Power's customers get to take full advantage of the most cost-effective supply-side alternative available. One of our objectives on the bid evaluation team is to ensure that all respondents are treated consistently and fairly. To accomplish that objective, SCS used only the specific information directly provided by the respondents in evaluating their proposals. In cases where information was incomplete, an estimate favorable to the respondent was made in the initial stage of the evaluation process until the respondent was able to clarify the specifics of the offer.

Q. What steps are taken with regard to the security and confidentiality of the proposals?

A. For the Gulf Power RFP, I distributed copies of all proposals received ONLY to bid evaluation team members. Distributed copies were numbered, and team members were requested to make no additional copies. All team members were required to keep proposals secure, or return them to me at day's end.

Q. Please describe how the alternative offers were initially economically screened?

A. After the four proposals passed the responsiveness screening, which verifies that all mandatory components of the offers were included with the proposal, then the economic portion of the analysis began. The initial screening of the offers was a "generation only" evaluation. All offers were analyzed using PROVIEW®, a production cost and optimization model. Specifically, a PROVIEW® case was created for each proposal and compared to a base case without that generation facility. The difference between these production cost simulations was considered the "energy savings" for that offer. Fixed capital and O&M costs for the alternative were also totaled and the net cost was present valued across a twenty-year horizon. These initial screening results are shown in Schedule MJB-1.

Q. Prior to the completion of the initial screening of the various alternatives to Smith Unit 3, did you and the other SCS employees working on the evaluations have any questions about the proposals?

A. Yes, the initial screening of the proposals is usually the most difficult because information is not shared uniformly. In some cases, assumptions had to be made about an offer to effectively analyze the proposal for the initial screening. SCS-Generation Planning and Development and SCS-Transmission Planning reviewed the offers during the initial screening and identified the additional information they would need to conduct their detailed analysis.

Q. The Gulf RFP made reference to transmission impacts and you mention above that SCS-Transmission Planning reviewed the offers during the initial screening. At what point did any transmission system impacts become a factor in the RFP evaluation process?

A. Although SCS-Transmission Planning reviewed the offers during the initial screening, it was not until the detailed evaluation phase that the transmission system impacts were incorporated into the process. For the Gulf Power RFP, a relative transmission evaluation was conducted for all of the proposals and any necessary transmission improvement costs were identified, and ultimately include in the economic analysis. It was necessary for Transmission Planning to initiate their review of the offers during the early part of the analyses to adequately assess any system impacts associated with the offers. The initial screening was a "generation only" analysis based on the information strictly provided by the respondents in relation to the RFP issued on Gulf's behalf and, therefore, any transmission impacts were not included.

Q. Did you contact the respondents to the RFP process asking them to clarify your assumptions about their proposals?
A. Yes, all respondents were contacted in writing on November 19, 1998 and asked for the additional information needed to fully evaluate their offer. Most of the uncertainty at this stage of the analysis concerned the reliability of the fuel supply, unit ratings, unit heat rates, and overall availability of the offers. Therefore, the questions were categorized into generation, fuel, transmission, and structure questions.

Q. As a result of this dialogue with the respondents, were any of the original proposals modified?
A. Yes, most of the original proposals were modified and two of the respondents made additional proposals for consideration under this RFP. This resulted in a total of nine proposals being carried forward in the final stages of the evaluation.

Q. After receiving the answers to your clarifying questions, was there a need to perform the analysis again to include this additional information?

A. Yes, each time a respondent provided updated information the analysis was repeated to ensure that the value of that revision was included in the relative ranking of the offers.

Q. At what point did you evaluate Gulf's Smith Unit 3 option?

A. I received the site specific Smith Unit 3 cost estimates on October 27, 1998. As I will discuss in a moment, this submission did not include gas transportation costs. The evaluation process was designed so that the evaluation of the self-build alternative would follow the same evaluation procedure that the proposals had already been through. This process design was created to ensure that the analysis procedure would not have a bias toward or away from the self-build alternative. The bid evaluation team also requested additional information from the self-build team when necessary.

Q. You mentioned earlier that Gulf's self-build submission did not include gas transportation costs. How were these costs factored into the analysis?

A. Originally, Gulf Power's plan included an estimated $90 million cost for construction of a gas pipeline to the

Bay County site. In September 1998, SCS issued a separate RFP for Firm natural gas service to the Smith site. The offers received in response to that Natural Gas RFP were generally less costly than Gulf's original plan. Information from this solicitation was used in the evaluation of the self-build proposal. Having multiple fuel supply alternatives allows Gulf Power to negotiate among the vendors to achieve a significantly lower pipeline cost for the facility than what was originally estimated.

Q. You mentioned earlier that your overall objective is to identify the most cost effective supply-side alternative. Do you consider the results of your evaluation to have achieved this goal?

A. Yes. The evaluation of alternatives for the Gulf Power solicitation did provide Gulf Power with accurate relative rankings of the proposals and the self-build alternative.

Q. What were the results of your evaluation?

A. The results of the evaluation reveal that the 540 MW self-build Smith Unit 3 is the most cost-effective alternative for the customers of Gulf Power Company. Referring to my Schedule MJB-2, this table outlines all of the final offers and their relative rankings after the detailed evaluation. One can see from this schedule that Gulf's Smith Unit 3 had a much lower cost than any of the competing offers. In fact, these relative rankings prepared by my team indicate more than $90 million accumulated NPV(2002$) savings over the next best alternative.

Q. Does this conclude your testimony?
A. Yes it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Supplemental Direct Testimony of
Maria Jeffers Burke
Docket No. 990325-EI
Date of Filing: May 17, 1999

Q. Please state your name and business address.

A. My name is Maria Jeffers Burke and my business address is 600 North 18th Street, Birmingham, Alabama 35202.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my testimony is to present the results of an updated economic evaluation of Smith Unit 3 which takes into account recent design and cost changes for the project. As described by Mr. Moore, the peak output of the unit has increased by 34 MW, the heat rate has changed slightly, and the total nominal cost has increased by $9.6 million.

Q. Have you prepared an exhibit that contains information on your updated evaluation?
A. Yes. I have an exhibit consisting of one schedule to which I will refer. This exhibit was prepared under my supervision and direction.

Counsel: We ask that Ms. Burke's Schedule 3 be marked as Exhibit ___ (MJB-3).

Q. Why did you perform a reevaluation of Smith Unit 3?
A. Gulf wanted to confirm that the proposed changes would actually improve the cost-effectiveness of the project.

Q. How did you perform your analysis?
A. I analyzed the total costs associated with the redesigned unit using the same PROVIEW evaluation methodology that was used in the previous ranking of Smith Unit 3 and the RFP alternatives.

Q. What were the results of your analysis?
A. The updated analysis shows that the evaluated NPV cost of Smith Unit 3 has decreased from $279/KW to $274/KW in 2002 dollars.

Q. What conclusions do you draw from this evaluation?

A. As shown on Schedule 3, this evaluation shows that Smith Unit 3 still provides much greater value than any of the alternatives proposed in response to the RFP. It also demonstrates that the incremental MWs resulting from the design change are a cost-effective capacity resource.

Q. Does this conclude your testimony?

A. Yes.

Q **(By Mr. Melson)** All right. With the preliminaries out of the way, would you give us a brief summary of your testimony?

A Certainly. Good afternoon, Commissioners.

Consistent with Florida's RFP rules, Gulf Power has prepared and issued an appropriate RFP; published that RFP in both local publications and trade journals; collected and clarified proposals from multiple respondents and analytically compared those proposals to Smith Unit 3 across a 20-year evaluation period.

The results of this analytical comparison revealed by far that the Smith Unit, 574-megawatt unit, is the most cost-effective alternative for the customers of Gulf Power Company. In fact, the relative ranking comparison, my exhibit MJB-3, shows that the net evaluated cost of the Smith Unit 3 is essentially $274 per kW. The next best alternative is almost $200 more, or $496 per kW. That's the basis that I used to conclude that Smith Unit 3 is the best supply-side alternative for Gulf Power's customers.

This concludes my summary.

Q Just so we're clear about the unit in which one of those answers was stated, you talked about dollars per kW. Is that a dollar per kW of installed cost or is that a dollar per kW net present value over 20 years of all of the costs and savings associated with the project?

A The dollar per kW numbers that I used for the evaluation is not an installed cost. It's a net evaluated cost so that you can compare CTs and combined cycles and different -- a variety of types of capacity on an equal basis using the installed cost as one of those components, but it's net of whatever energy benefits that that alternative brings to the table as well. So it's a net evaluated cost.

MR. MELSON: Ms. Burke is available for cross.

COMMISSIONER DEASON: Ms. Kamaras.

MS. KAMARAS: No questions.

COMMISSIONER DEASON: Staff.

CROSS EXAMINATION

BY MS. JAYE:

Q Ms. Burke, I've got some questions about the confidential information beginning on Page 2. This is Gulf's confidential response to Staff's Interrogatory No. 1. I want to reference the number at the top of the column entitled "Generation & Transmission Total Cost Accumulated Present Value." Is this number the same value that's included for Smith Unit 3 in Exhibit

MJB-2 of your testimony, and I believe that was identified as Exhibit 9?

A Yes, it is.

Q Could you explain why, in your opinion, it is appropriate to portray a project's cost-effectiveness in NPV dollars per kilowatt rather than in total dollars?

A Because projects, especially when you're evaluating projects in an RFP situation, you're going to get projects that are a variety of sizes. And it's important to make sure that you try to put them on an equal basis. We found through the different RFPs that Southern Company has been through that putting it on a dollar-per-kilowatt basis really values that project kind of on a stand-alone basis. A project may be very small. You don't want to overlook the value that that small project has or that a large project has. If you put it on a per kW, what are you getting for your dollars, we found it to be a better analysis.

Q Can total dollars associated with each project be estimated by multiplying the unit size for each resource option by dollars per kilowatt values that are contained in Exhibit 9, MJB-2, of your testimony?

A I'm sorry. Can you repeat the question?

Q Certainly. Can the total dollars that are associated with each project be estimated by multiplying the unit size of each resource option by the dollars per kilowatt values contained in Exhibit MJB-2 of your testimony?

A Yes. We did that when we calculated the $90 million of savings. It's really a conservative estimate. It doesn't take into account the additional 100 megawatts that Smith Unit 3 brings.

Q Turning now over to Page 90 of the confidential composite exhibit.

MR. MELSON: What was that page number again, please?

MS. JAYE: 90.

MR. MELSON: Thank you.

Q **(By Ms. Jaye)** Actually starting at Page 91. This particular page contains Late-filed Exhibit 4 to Mr. Pope's deposition. Are you the witness who actually performed the analysis that is contained in this exhibit?

A Yes, I am.

Q Okay. Ms. Burke, looking at that last column, Accumulated Present Worth Revenue Requirements, would you say that this column represents the true costs that are associated with this project?

A This particular page was updated and revised so I guess I'm a little hesitant to say yes. It does reflect -- I mean, in principle it does. It has a small calculational mistake in it, so, I guess, it's not the final numbers.

Q Is the change due to the change up to 574 megawatts for the proposed Smith Unit 3?

A Yes, it is. We had not calculated the losses correctly. We had not taken into account the dollars appropriately on this page. We did that in an analysis beyond this one.

Q On the page following, on Page 92 -- I'm sorry. It's on Page 93. There's some numbers outside of the columns. Do these numbers represent the present worth revenue savings for Smith Unit 3 over the proposed RFP options?

A Yes, it does.

Q Is that savings on a total dollar basis?

A Yes, it is.

Q Looking at these pages as a whole, does the revenue requirement data that is contained in them give a true estimate of the magnitude of cost-effectiveness for the proposed Smith Unit 3?

A On a relative basis it does. Just like you were asking Mr. Pope about the transmission dollars, the numbers that we put in this analysis for the transmission cost were all relative to Plant Smith, so on a total dollars, it's not the absolute dollars, but in a relative sense it has all the components.

Q Were the dollar values shown in this exhibit the result of rerunning the PROVIEW model?

A Yes, it was.

Q Could you explain that how that PROVIEW model is run? Just give a quick overview?

A Certainly. The PROVIEW model contains all of the units for the Southern electric system. We also put in there what we call a typical week load shape for every month of the year. That load shape is divided up into weekend, weekday, weeknight periods and the units are dispatched on a lowest dispatch price basis, lowest first basis, and really ranked up within that dispatch and estimated the utilization of those units. That PROMOD production cost also takes into account the forced outage, the scheduled maintenance. It can take into account fixed cost. We prefer to use the fixed cost externally in a spreadsheet so we can show them to you guys in a format like this so we don't include anything other than the variable components of the alternatives that we're looking at when we do the production costs.

What we do for the analysis that we do for the dollar-per-kW type of analysis, we really do exactly what Commissioner Jacobs asked. We run one without the Smith unit in there as a placeholder type of case, and then we run it with the Smith unit in there as a change case, and we take that delta so that you can actually see what is the production cost with the unit in there, what is the production cost with the unit not in there.

Q I'd ask for you to turn back to Page 2 of the confidential composite exhibit, which has been identified as Exhibit 8. The tables in this exhibit refer to a base case plan. Would you tell me what comprises that plan?

A That base case utility cost is the fuel, the variable O&M, the emissions cost of all of the existing units in our fleet. In addition, it includes whatever expansion plan costs are in that case, including those fixed costs for the expansion plan, what we call generic unit additions on the system through time, and the fuel variable O&M and emissions from those generic units.

Q What are generic units made up of?

A Southern Company Services' Engineering

Department creates a technology data book for us each year that is a generic -- what's a generic CT cost; what's a generic combined cycle cost; what's a generic coal plant cost. And we use those costs and operating parameters in the model as generic units.

Q Referring now to your base case plan, what generic units are included in the basis case plan that makes that base case plan different from what was proposed in the RFPs?

A How would the generic units differ from the RFP units?

Q Yes.

A I would say that they're very different. The generic units are usually kind of generically within -- that we have to create a generic location within a specific portion of our system, maybe a Central Alabama or a Central Georgia-type generic site. But I've imagined that the RFP respondents have very site-specific information in them. I know that the fuel information that we used for the production cost runs were very site-specific. I'm sure that the respondents also took into account some site-specific characteristics of their units when they proposed those to us.

Q Is the cost of a base case generic expansion plan contained in the column on these pages entitled "Base Case Utility Cost"?

A Yes, expansion plan costs are included in that.

Q Refer now over to Exhibit 7 on Page 7. This is Gulf's response to Staff's Interrogatory No. 2. I'm sorry.

A Sorry. I was in the wrong exhibit. Yes. Glad you found that.

Q Give you a chance to have a look at that Page 7. Do the numbers in these columns refer to the number of 300-megawatt-block size generic CC and CT units to be added?

A Yes, they do.

Q Could you explain how that works, the 300-block size additions?

A The Southern electric system is a very large system from a generation planning perspective. And in the generation planning group that we work in, we work very hard to make sure that we are really adding the right technology that the system needs in a particular time and not trying to put a CT in there because it was an exactly 80-megawatt size. We really go for the economy as a scale rather than, I guess, a convenient block size of the generation that's available.

For that reason, we put CTs and CCs in the case generically as 300-megawatt-block sizes. The system does grow 600 to 700 megawatts a year. And so, usually the model puts in -- one of each is really the most common one when you're in complete balance. They'll put one CT and one CC in it, in the mix. But in the case we use a 300-megawatt-block size to help make sure that we are adding the right technology and not necessarily the exact convenient size of a unit that could be added.

Q Where on Southern Company's system are the generic unit additions located?

A I believe they are in -- there's a Central Alabama and a Central Georgia location.

COMMISSIONER JACOBS: So help me understand this. If we get -- now we come to Gulf and they have a 400-and-some-odd megawatt requirement, would that 300 block -- how would they interplay with one another for planning purposes?

WITNESS BURKE: What I did was I took into account the -- each one of the respondents, and even in Gulf's self-build case, I basically scaled them up to a 600-megawatt-block size for the production costing methodologies. I still had all of the fixed costs out here, dollars per kW. So in order to capture the energy benefit that that unit brings the system -- and even under the expansion plan savings so that I wouldn't disadvantage one of the respondents over another -- I scaled them all to 600 megawatts. And that way the cases, the base case and the change case, are equal megawatt cases and so none of them has to bear the burden of more cost to account for that expansion plan unit through time. So for the production cost purposes, it's really done on an equal megawatts case.

COMMISSIONER JACOBS: Now, your view at that moment is from the Southern Company view; is that correct?

WITNESS BURKE: That's right.

COMMISSIONER JACOBS: That's the RFP respondents. Then they're going at Gulf's need, correct?

WITNESS BURKE: That's correct.

COMMISSIONER JACOBS: How do you get them to match up?

WITNESS BURKE: Because we're one pool, we have one dispatch pool, I think that my analysis really accurately reflects how that unit would be dispatched in the Southern electric system.

COMMISSIONER JACOBS: Oh, I see.

WITNESS BURKE: Whether it's a respondent or it's a self-build or however, it's going to be dispatched up against all of the units within the Southern electric system.

COMMISSIONER JACOBS: Are they -- are they responding to specifications of a 600 or just to the -- I'm sorry. I understand. You take what they give you and you project it in that way.

WITNESS BURKE: That's right, within the analysis. We just do that for analysis purposes.

COMMISSIONER JACOBS: I see.

COMMISSIONER CLARK: I'm not sure I understand that, and maybe it would help if you looked at your Exhibit 2. I don't know what it is. Is it Exhibit 9, Schedule 2?

MS. JAYE: Yes, Commissioner.

COMMISSIONER CLARK: You have the bidders listed and you indicate their rank and you indicate how many megawatts, evidently, they bid. For instance, with Respondent B combustion turbine and a 20-year pricing, they bid in 486 megawatts; is that right?

WITNESS BURKE: I'm having trouble finding that exhibit.

COMMISSIONER CLARK: It's attached to your first Direct Testimony.

WITNESS BURKE: Oh, to the first one. That's why.

MR. MELSON: Commissioner Clark, the version attached to the Supplemental Testimony contains the updated unit size for Smith 3, and if you're going to look at specific numbers, it's the same concept. That might be the better one to look at.

WITNESS BURKE: It would help me.

COMMISSIONER CLARK: It has the --

MR. MELSON: It has exactly --

COMMISSIONER CLARK: -- same injection? Is that what it is? Lose the megawatts a little bit? It doesn't make any difference for my question.

I guess the question I have, what you're doing is -- for instance, for the 486, you do some extrapolation up to 400 -- I mean 540, so you're on the same basis or does everybody get up to 600?

WITNESS BURKE: I scaled every one -- every one of the alternatives were scaled to 600 megawatts and that way it didn't -- because my expansion plan alternatives were 300-megawatt-block sizes, it wouldn't change the expansion plan. That's why I chose one that was the same block size as my expansion plan unit.

COMMISSIONER CLARK: Let me ask you this: As I understood your revised estimate for Smith, because you went up in the number of megawatts, you're actual per-unit cost came down?

WITNESS BURKE: That's correct.

COMMISSIONER CLARK: Could you -- but you didn't make the same sort of assessment for any of these other ones when you scale them up to a larger megawatt?

WITNESS BURKE: The only reason that the evaluated cost of Plant Smith went down, decreased in the evaluated cost, was because the size of the unit -- the actual cost of the unit did actually go up. It was $9.2 million, I think, that was actually added to the cost. So the net present value, the revenue requirement cost actually went up. But we reran that also through the production costing method as well and the energy savings went up as well. So when the cost went up some; the energy savings went up some as well.

So if you look at what -- the net evaluated cost actually came out to be lower than previously. But even in either one of the production cost methods that I did for the self-build, either the 574 or the 540-megawatt-slice size in that production cost analysis, I scaled both to 600 megawatts so that they would be on an equal megawatt case with the base case.

COMMISSIONER CLARK: I guess my question is, can you assume the same sort of increase in -- if you increase the unit size for those people responding, might they experience the same kind of decrease --

WITNESS BURKE: Well --

COMMISSIONER CLARK: -- in the overall cost or whatever?

WITNESS BURKE: There's a lot of ways I could answer this. A CT, for example, is not going to have a design change like the combined cycle had. So that's part of my problem. But in the analysis, for the production cost value of these units, all of these units were scaled to 600 megawatts.

COMMISSIONER CLARK: Let me ask you a different question and I think Mr. Melson was trying to get you -- trying to somehow explain why there was such a big difference between No. 1 and 2. He said it was net of energy?

WITNESS BURKE: That's true.

COMMISSIONER CLARK: Explain to me what -- these are capital costs then?

WITNESS BURKE: No. It is capital cost. If you sum up all of the capital requirements, what those revenue requirements would be for each one of these alternatives and you get a total fixed cost, and you take the delta in the production cost; if I didn't have this unit this is what my production cost would be; if I did have this unit, this is what the production cost would be.

I take those total dollars and divide it by the 600 megawatts that I used in that piece of the analysis to create $1 per kW energy savings. And I think that's actually included in what the Staff has pulled out for the confidential piece of the evaluation. And I would be glad to walk you through that if I can find one in here. Do you know what page they're on?

MS. JAYE: I believe it's on Page 2 and following.

COMMISSIONER CLARK: Page 2 of the confidential exhibit?

MS. JAYE: Yes, Commissioner.

WITNESS BURKE: Yes. This is a great chance to walk through and show you exactly how we took into account all of the fixed components and all of the variable components of the analysis.

Page 2 of the confidential material shows how we added up all of the fixed costs to get a total fixed cost for this particular alternative. This particular page covers the 20-year self-build alternative. There's separate pages for each one of the respondents and we did the same thing for those guys as well.

COMMISSIONER CLARK: Which column shows total fixed costs?

WITNESS BURKE: The sixth column over from the left.

COMMISSIONER CLARK: Okay.

WITNESS BURKE: And then the next column over, the next three columns deal with the capacity -- with the energy savings, the variable cost. And this is in traditional generation expansion plans, a combined cycle, for example, is going to cost more, but it evidently has more energy benefits to your system or you would never add it. So that's exactly what I tried to do, is to capture what the energy benefits are of this particular alternative. Once I have those total dollars, I divide it by the 600 megawatts that I used for those two columns, the base case utility cost and the proposal utility cost. That delta is divided by the 600 megawatts and is shown in the column that's called "Energy Savings and Expansion Plan Savings."

Then the column that's just to the right of that is the total cost, and that is simply the column that was the total fixed cost. And we subtract off what we just calculated as the energy benefits associated with this unit. And then all we do with that total cost column then is to create a net present value of those revenue requirements to get the total net present value of the generation cost.

COMMISSIONER JACOBS: Could you help me understand again your base case analysis?

WITNESS BURKE: Yes. The base case analysis is run with a 600-megawatt placeholder in there so that it had has no energy benefit. That 600-megawatt, we basically went with a 600-megawatt placeholder that has no dispatch capability. So then when you run the change case, you put a 600-megawatt bid or 600-megawatt self-build alternative in there.

COMMISSIONER JACOBS: And can you dispatch or not?

WITNESS BURKE: That's right. The self-build alternative or the proposal alternative is dispatched in that production cost model.

COMMISSIONER JACOBS: Okay.

COMMISSIONER CLARK: Which column do you use to calculate your net present value?

WITNESS BURKE: The column that is shown as the total cost there right beside it has a present value factor. We simply multiple those two together to get the column that is on, I guess, to the right of that that's called the Net Present Value of Total Generation Cost. You can, as a function, just net present value that column, and we have done that right under the column -- right under the word you can see the 383 that is shown there. And then we -- just to make sure that we're checking the numbers right, we do an accumulation of those numbers. And at the bottom, the Generation Total Cost Accumulated Present Value column that is shown there, the very last number is also 383, and that way we can check and make sure that we did present value those correctly.

COMMISSIONER CLARK: Sorry. Where?

MR. MELSON: Ms. Burke, you blurted out the same number twice. I think this particular one in context is probably not confidential, but you need -- you ought to be careful about numbers.

WITNESS BURKE: Well, it's the net present value so --

COMMISSIONER CLARK: Let me just ask you a little differently. How do you use this spreadsheet on Confidential Exhibit Page 2 to come up with the number that you have in the last column on your Exhibit MJB-3, which is attached to your Supplemental Testimony?

WITNESS BURKE: There are additional costs other than generation costs -- generation production costs, and that's why I have a section on this Page 2 that deals with transmissions; what are the grid and connection costs, what are the losses, what's the total present value of those. And adding those to the generation costs, I get the column that is on the far right-hand side that present values to the 274 that we talked about in that summary, MJB-3, the relative ranking.

COMMISSIONER CLARK: Okay. Can you sort of give a big picture of what you think the costs -- what were the particular aspects of these proposals that made them so much higher than the self-build?

WITNESS BURKE: Each one of the proposals that were sent to us were different so it's hard to create one that, like you say, that is what was the refining factor that made them so much more expensive.

I know that the accumulated net present value of these in terms of cost is very close to what we published in the RFP, like Attachment C; the costs associated with what we had expected Plant Smith to come in with.

So I don't know if they were targeting a specific target and they didn't get as low as our self-build team did when they put the RFP out for fuel. I'd say there is not one overriding fact like Gulf picked the best transmission case. They did take the best transmission site, but they put that in the RFP. This was a good transmission site. So --

COMMISSIONER CLARK: You mean in the RFP. You indicated I think some -- maybe Staff or somebody indicated the RFP says, you know, best place to locate this is Panama City.

WITNESS BURKE: Yes.

COMMISSIONER CLARK: And you can't -- you would be uncomfortable saying that a good deal of the difference in cost is the result of those bidding not proposing a site in Panama City?

WITNESS BURKE: If there had been a site in Panama City, they would have had a significant cost savings. I mean, that's shown in one of the transmission interrogatories, I think. Mr. Pope covered that.

COMMISSIONER CLARK: Let me ask the question a little bit differently. When you put out your RFP, do you -- as I recall, you indicate what you think the price would be if you built it yourself?

WITNESS BURKE: I understood that was a requirement of the RFP rules in Florida.

COMMISSIONER CLARK: What did you put out for the net present value total cost? What was it?

WITNESS BURKE: Well, we actually included the cost of all of these different components. We did not include a net evaluated cost like we do in the evaluation, but we did include what the cost of the equipment itself was going to be, what the cost of the gas lateral to the facility was.

COMMISSIONER CLARK: Well, if you did the calculation, what would you have come up with for a net present value?

WITNESS BURKE: I don't have that evaluation done.

COMMISSIONER CLARK: Let me ask you this differently. You indicated that you think the bidders may have come in around these prices because of what you put out?

WITNESS BURKE: That's correct.

COMMISSIONER CLARK: Well, what did you put out that caused them to come around those prices?

WITNESS BURKE: The plan -- the Need Study -- actually the last page of the Need Study shows Attachment C, what we had in here as far as a planned unit data, and we did use some generic unit cost information. I understood Gulf was not really -- they didn't have a lot of different sites, specific information really developed at that point when we published the RFP. So we used some generic information about what the total direct cost would be to install a combined cycle at that site. We used some of the site-specific information that we had, like what it was going to cost to build a gas lateral to the facility and those types of things. And I don't know why -- I don't know -- I think the only component in here that was rather large was the $90 million of gas lateral pipeline cost that was essentially eliminated through time with the RFP that Gulf put out for the fuel.

COMMISSIONER CLARK: But the $90 million would have been the lateral up to Atmore, Alabama?

WITNESS BURKE: Yes. That's what I understood.

COMMISSIONER CLARK: And by eliminating that --

WITNESS BURKE: Gulf was able to significantly reduce the cost of this unit.

COMMISSIONER CLARK: But you can't tell me what you actually put out in terms of the net present value for the self-build?

WITNESS BURKE: Well, the information that we needed to publish just wasn't a net present value figure. So I just don't have that at my fingertips.

COMMISSIONER CLARK: But couldn't it be calculated?

WITNESS BURKE: Yes, ma'am, it could be.

COMMISSIONER CLARK: You had to put that out in August of '98? Is that when you went out --

WITNESS BURKE: I believe that is right. August 21st. Yes.

COMMISSIONER CLARK: I would be interested in knowing what -- using the parameters you put out in a bid, what would have been the net present value total cost; what would have been the equivalent figure to the one you show on MJB-3. And Staff, if you would make sure that I get that.

MS. JAYE: Yes, ma'am.

COMMISSIONER CLARK: But it would be your testimony it's somewhere around 500 because that's where all the bids came in?

WITNESS BURKE: Yes, ma'am, it would be.

COMMISSIONER CLARK: And is it your testimony that you think a good deal of that can be attributed to the gas lateral?

WITNESS BURKE: Yes, I believe it is.

COMMISSIONER CLARK: Okay. And the fact that it was -- okay, to the gas lateral. Because your proposal does show it as being sited in Panama City?

WITNESS BURKE: Yes, it does.

COMMISSIONER CLARK: Okay.

MS. JAYE: I was going to ask, Commissioner Clark, in what form would you like the exhibit? Would you like it in a tabular form?

COMMISSIONER CLARK: No. If you would just give me, you know, what -- as compared to what you currently estimate for the Smith Unit 3, what did your -- what would have been the net present value total cost for the floor plan given the parameters you put out in the bid.

WITNESS BURKE: I know it's in the $500 kV range, but I don't have that spreadsheet with me today.

COMMISSIONER CLARK: And by someone else bearing the cost of the gas lateral, you're in better shape?

WITNESS BURKE: Well, you're not getting it for free. They're just embedding it differently in the pricing, yes.

COMMISSIONER CLARK: Okay. Thank you.

MS. JAYE: Commissioner Clark, would you like a late-filed exhibit number for that?

COMMISSIONER CLARK: Yes.

MS. JAYE: Yes. I think we're on Exhibit No. 11. Call this Late-filed Exhibit 11.

COMMISSIONER DEASON: Okay.

MR. MELSON: Commissioner Clark, if we call our next witness on the stand, we think this number exists in a way that we probably can get it over the telephone.

COMMISSIONER CLARK: That would be fine.

MR. MELSON: And rather than doing a late-filed exhibit, I would much prefer to get that information back verbally during the day today.

COMMISSIONER CLARK: That's okay with me.

MR. MELSON: Let me consult with the witness one minute.

(Brief recess taken.)

Q **(By Ms. Jaye)** Ms. Burke, turning to Page 2 on the confidential exhibit. There is a column entitled Proposal And Utility Cost. Looking at that column, how does it explain how the expansion plan differs from the base case plan?

A Just by looking at this number you probably couldn't tell how the base case plan and the expansion plan change. You would have to look at our answer to Interrogatory No. 2 to pull that. But it is -- the cost of that change is included in that column.

Q In calculating that proposal utility cost, would the first 600-megawatt block of generic capacity be replaced by the Smith Unit 3 and RFP respondent, et cetera?

A Yes. The base case is run with a placeholder of 600 megawatts and that is replaced in the proposal utility cost case with whichever proposal, whichever alternative you're doing the evaluation.

Q Do the capital and O&M cost columns on Page 2 of the confidential exhibit portray the incremental cost of the new unit addition?

A Yes, it does.

Q Do the columns entitled "Base Case Utility Cost" and "Proposal Utility Cost" on this same page refer to the total system revenue requirements associated with the entire Southern Company system, including all fuel impacts?

A Yes, it does.

Q How can cost-effectiveness to Gulf Power Company for this unit addition be determined when the cost-effectiveness analysis was performed under a Southern Company system basis?

A I believe that, especially in the case of -- well, in the case of a combined cycle, this particular combined cycle is going to dispatch numerically really soon in the Southern Company dispatch. Because the Southern Company dispatch pool is done on a pool basis, the units are dispatched up against all of the Southern Company units. Smith Unit 3 actually has a very low dispatch price, and, therefore, it's dispatched very early in the dispatch algorithm. Because the Southern electric system has a pool dispatch, I think that this is an appropriate method to use for an evaluation of any set of alternatives that you're looking at.

Q Remaining with this Page 2 of the confidential exhibit for awhile, on Page 2 in the following pages, the Transmission Grid and Connection Accumulated Present Value column shows a certain number and it changes relative to the base case. On the subsequent pages of this analysis, which represents the cost for the RFP projects and the respondents, does this same column indicate the incremental difference between their transmission costs and the transmission costs associated with the

Smith Unit 3?

A Yes, that's correct. Plant Smith had the lowest of all of the costs for the transmission grid connection costs and that's the way the transmission planning provided these numbers to me.

Q If the actual revenue requirements associated with transmission costs for Smith Unit 3 and the RFP respondents were shown, would the total cost differential between the Smith Unit 3 and the RFP projects change?

A The differential between Smith and the other units wouldn't change because you would just add that many dollars per kW back into all of the different respondents, so the relative number between -- differential between those would really not change.

Q I'd like to turn now to Composite Exhibit No. 7, which is the nonconfidential exhibit that Staff has offered.

COMMISSIONER DEASON: Before we leave the confidential exhibit, I have a question.

MS. JAYE: Okay.

COMMISSIONER DEASON: The total cost column, I take it, is a function of the total fixed cost and the energy savings, and those two numbers are netted together; is that correct?

WITNESS BURKE: That's correct.

COMMISSIONER DEASON: Could you explain to me again -- and you may already have. And if you have, could you explain again what the column entitled "Energy Savings" represents?

WITNESS BURKE: Yes. It is the difference between the two columns just to the left of that. You take the total dollars of the production cost with its unit in versus the production cost of just the placeholder in instead, and divide it by the total number of megawatts, this 600-megawatt placeholder size that we used in this evaluation, you'll get the numbers that are shown in that energy savings and expansion plan number.

COMMISSIONER DEASON: And you used the same methodology to evaluate the other alternatives?

WITNESS BURKE: Yes, I did.

COMMISSIONER DEASON: I don't want to divulge any confidential information. Can you just give me generically why the self-build energy savings are of the magnitude they are in comparison to the energy savings of some of the alternatives? Is there some generic reason for that?

WITNESS BURKE: Let me see if I can find one that I can talk you through. The -- I guess Page 10 of this is the next best alternative, so that would be a good one to talk you through.

It says the same thing. I guess the components of this particular proposal really only included the capacity cost. They didn't break out fixed O&M and different components. They really just included one fixed charge. People do it different ways and we just adapt to that. So, the fixed costs are all included in that column that we show here called "Capacity Cost."

Then we did the same thing. We ran that same base utility cost case with the 600-megawatt placeholder and then we ran this proposal in here, which was a CT alternative, for 20 years. You can see that it's really not surprising when you think about it, that the CT has very little energy savings on a dollar-per-kW basis. You would expect that a CT would not have a lot of energy savings over generic units within your mix, so that's not surprising. You can see that the numbers start off very low. There is some --

COMMISSIONER DEASON: Just because it would be dispatched very late?

WITNESS BURKE: That's right. In the dispatch order, they would be much higher in the dispatch order. There is some -- you see some wiggle room within the numbers. That really has to do with the expansion plan changing through time, maybe a combined cycle was built in the expansion plan to optimize the fuel, the total cost. So within the expansion plan, we don't really hold that constant. We let the expansion plan change with the alternative that's being proposed. If a CT is proposed, it's not uncommon for the expansion plan to change somewhere through time and to add more combined cycles to bring the mix back into balance.

So you can see that the numbers change through time. I think that what you've got there is really some more expansion plan changes than just fixed energy savings.

Q **(By Ms. Jaye)** Ms. Burke, in relation to those confidential items -- you don't have to open them up again. Is it your opinion that the most cost-effective alternative, and the fact that Smith Unit 3 looks to be the most cost-effective alternative from the runs that were done and included in this confidential composite exhibit, means the most cost-effective alternative to all Southern Company utilities?

A I think it's more of a relative ranking, relative to all the other alternatives that you have on the table. Smith Unit 3 is overwhelmingly the lowest cost alternative.

Q I'd like to refer now to Composite Exhibit 7 offered by Staff. Will you turn to Page 192?

COMMISSIONER JACOBS: Can I clarify something? Does the savings for Smith 3 include the enhancements?

WITNESS BURKE: Yes. I did the analysis for both a 540-megawatt size and a 574-megawatt size. The numbers that we were just looking at on Page 2 of the confidential material does include the 574-megawatt size.

Q **(By Ms. Jaye)** I'd like for you to take a look at pages 102 through 230. Could you tell me what this document is?

A This is my deposition from May 11th.

Q Do you have any changes or additions to make to this?

A No, I don't.

Q I'd like you to turn to Pages 2 through 13, again of the confidential information. Looking now at Page 1 and following, this is Gulf's response to Staff's Interrogatory No. 1. Was this response prepared under your supervision and direction?

A Yes.

Q Can you briefly summarize the reasons for the differences in natural gas price forecasts between Smith Unit 3 and the RFP alternatives?

A Certainly. The RFP alternatives, they're proposals included a particular pricing or particular index for the fuel supply. To the extent that we could model those, we used our own fuel forecasts through time and tried to figure out what the basis differential was between our own fuel forecast and that indexed location that they used in their bids.

Q Turning back again to the Composite Exhibit 7, which is the nonconfidential information provided by Staff, if you would turn to Page 15, please. This is Gulf Power's response to Staff's Interrogatory No. 18. Was this response prepared under your supervision and direction?

A Yes, I believe it was.

Q Can you briefly describe the status of backup fuel capability for Smith Unit 3 under the RFP alternatives?

A Smith Unit 3 does not have a fuel oil backup system. They have firm fuel delivery guaranteed from a particular supplier now. Several of the respondents to the RFP were in a similar situation. Respondent A proposed in two facilities; one had fuel oil backup, the other one did not. Both of those were base-load type of facilities and they were concerned about their air permit as well. Respondent B did include fuel oil backup and Respondent C did not include additional backup.

Q Turning now to Pages 16 through 18. These are Gulf's responses to Staff's Interrogatories 19 and 20. Were responses to Interrogatories 19 and 20 prepared under your supervision or direction?

A I did help pull these responses together, yes.

Q What sources did Southern Company use when it created the price forecast for coal, natural gas and oil?

A The coal price that we used for this particular exhibit is a Central Appalachia coal. It's FOB at the mine mouth. The gas is a Mobile Bay price and the oil is a Gulf Coast price.

MS. JAYE: No further questions.

CHAIRMAN GARCIA: Okay. Commissioners? Redirect?

MR. MELSON: I've got a few.

REDIRECT EXAMINATION

Q **(By Mr. Melson)** Ms. Burke, if you turn back to Interrogatory 18, which we were just looking at on Page 15 of Exhibit 7, is it fair to say that Respondent C, who did not provide fuel oil backup, did quote a firm gas transportation supply?

A Yes, they did quote the price. That is included in their proposal.

Q And the respondents who quoted fuel oil backup, did they have firm gas transportation or were they relying on some other gas arrangements?

A There was one proposal that did include both.

Q You were asked some questions about Pages 91 through 93 of Confidential Exhibit 8, which was a comparison of Smith to the RFP responses on a total dollar basis. Could you turn to Pages 117 and 118 of Exhibit 7 and tell me if that is a summary -- a nonconfidential summary, if you will, of the information that Staff was referring to in the confidential exhibit?

A Yes, it is a summary of that same information. This particular one that I have on Page 117, someone has noted on here 540 megawatts. That's not true. This is the 574-megawatt size analysis, but this is before we found the transmission loss miscalculation. So this is not the final numbers.

Q If you turn to Page 118, is Page 118 what you would regard as the final numbers?

A Yes.

Q And so based on that method of analysis that the Staff asked you to perform, that would show the self-build alternative being roughly $121 million better than the next most cost-effective?

A That's correct.

MR. MELSON: That was all I had on redirect. If we could stand in place for a few seconds. Let me check on the status of the answer to Commissioner Clark's question.

COMMISSIONER CLARK: Mr. Howell can give it to us.

MR. MELSON: I think Mr. Pope was the one who had the phone conversation. I think what we're going to have -- we're going to ask Ms. Burke, after she leaves the stand here, to talk with her person back in Birmingham who has hands-on access to those numbers and confirm that they, indeed, are looking at the correct ones before we give you a number. We want to make sure we got absolutely the right one. If we could have permission to bring Ms. Burke back here in a few minutes after we finish with Mr. Howell?

CHAIRMAN GARCIA: Sure.

MR. MELSON: And with that, I move Exhibit Nos. 9 and 10.

CHAIRMAN GARCIA: There being no objection, show 9 and 10 admitted.

(Exhibits 9 and 10 received in evidence.)

MR. MELSON: And Gulf Power would call Mr. Howell.

CHAIRMAN GARCIA: Let's take 15 minutes.

MR. MELSON: Great. Thank you.

CHAIRMAN GARCIA: And we'll start back up at 3:00 p.m.

(Brief recess.)

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COMMISSIONER DEASON: We'll go back on the record.

MR. MELSON: Commissioners, I brought Ms. Burke back on the stand to answer the question Commissioner Clark had about what number would go on Exhibit MJB-3. We had run the -- what we call the Attachment C numbers, which was the numbers that were published with the RFP.

Q **(By Mr. Melson)** Ms. Burke, could you tell us what that number would be on a total generation and transmission basis, which is the basis that's reflected on MJB-3?

A Certainly. The total net present value for generation and transmission is $325.56 per kilowatt.

Q And so rather than the 500 rate that you had recollected today, it's actually $325?

A Yes. The number that I was using from memory, we had done at that point a generation-only type of analysis, and it did not include $109 a kilowatt for transmission benefit.

So the generation-only number that I was remembering is actual $435 a kW. When you subtract off that transmission benefit, you get to the number that we're talking about, the 325.56.

COMMISSIONER CLARK: So they weren't even close to what you put out in the RFP.

WITNESS BURKE: That's correct. On a generation-only basis, they were pretty close, when -- the transmission benefits. Even Attachment C numbers are better than the next best alternative respondent in the RFP.

COMMISSIONER CLARK: Okay.

MR. MELSON: Can Ms. Burke be excused?

CHAIRMAN GARCIA: Yes.

COMMISSIONER CLARK: Let me just ask: The 325 number you gave me is the same -- is the number you would enter on your exhibit? We're comparing apples to apples here?

WITNESS BURKE: (Nodding head.)

COMMISSIONER CLARK: Thank you.

(Witness Burke excused.)

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MS. JAYE: Commissioner Clark, does that therefore obviate the necessity for the late-filed exhibit -- (inaudible) --

COMMISSIONER CLARK: (Inaudible)

(Court reporter asked for clarification.)

CHAIRMAN GARCIA: That that will now make the late-filed exhibit unnecessary, that last one. I don't think we have any late-filed exhibits. Okay.

MR. MELSON: And one housekeeping matter, Commissioners. I have passed out -- it's on the table in front of you -- the errata sheet to the deposition of Mr. Marler. His deposition is included in Staff's Exhibit 7, and when he was on the stand I forgot to hand out his errata sheet. I'd ask, perhaps, if we could mark that as Exhibit No. 11 and have it admitted into the record.

CHAIRMAN GARCIA: Do we have an Exhibit 11?

MS. JAYE: We do not have an Exhibit 11, no.

CHAIRMAN GARCIA: All right. This is Exhibit 11, then.

(Exhibit 11 marked for identification and received in evidence.)

MR. MELSON: Also, just as an update, at Staff's request we have filed the firm transportation agreement that was entered into on Friday with the clerk's office, accompanied by a notice of intent to request confidential classification. My understanding is Staff may want to make that agreement a formal part of the record.

MS. JAYE: Yes. Staff would move to include in the Composite Exhibit No. 8, this letter.

CHAIRMAN GARCIA: Very good. That's part of Composite Exhibit No. 8. Okay.

MR. MELSON: And we've called Mr. Howell to the stand.

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M. W. HOWELL

was called as a witness on behalf of Gulf Power Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MELSON:

Q Mr. Howell, would you state your name and business address, please?

A My name is M. W. Howell. My business address is One Energy Place, Pensacola, Florida 32501.

Q And what is your position with Gulf Power Company?

A Manager of system planning and transmission control.

Q And have you prefiled eight pages of direct testimony in this docket?

A Yes.

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

A No.

Q And if I were to ask you the same questions, would your answers be the same?

A Yes.

MR. MELSON: Mr. Chairman, I'd ask that Mr. Howell's direct testimony be inserted into the record as though read.

CHAIRMAN GARCIA: Okay.

WITNESS HOWELL: Let me correct something I said. I don't often get that question. My direct title is manager of transmission and system control. I think I said it wrong.

CHAIRMAN GARCIA: Okay; with that correction.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 990325-EI
Date of Filing: April 5, 1999

Q. Please state your name, business address and occupation.

A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.

A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission, Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution systems; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I am a member of the Engineering Committees and the Operating Committees of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council, and have served as chairman of the Generation Subcommittee of the Edison Electric Institute System Planning Committee. I have served as chairman or member of many technical committees and task forces within the Southern electric system, the Florida Electric Power Coordinating Group, and the North American Electric Reliability Council. These have dealt with a variety of technical issues including bulk power security, system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, and system production costing.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to summarize the requirement which our customers have for the 540 MW combined cycle addition at Plant Smith.

Q. Are you sponsoring any exhibits to supplement your testimony in this proceeding?

A. Yes, I am sponsoring Sections 1, 2, and 9.4, as well as Appendix A, of the Need Study filed in this docket.

Q. What is the first data which Gulf examines in determining a need for future capacity?

A. The load forecast is the first major input. The Company's Witnesses Neyman and Marler have described in detail what goes into preparing our forecast, the state of the art computer models we use, and the integration of expected conservation and other adjustments to develop a sound forecast. The result is a forecast which predicts with reasonable accuracy what our future demands will be. The fact that we have a forecasting accuracy that places us in the top third of state utilities is testimony to the quality and dependability of our forecast.

Q. What is the next step in the process?

A. We compare our load forecast to our available capacity. Our goal is to have enough generation resources to cover our load with a reasonable reserve margin. As covered in Mr. Pope's testimony, we will have adequate capacity through 2001 by using external power purchases and by relying upon available Southern system reserves. By 2002, when the purchases expire, we will be 427 MW short of capacity without additional resources. The 540 MW addition at Smith Plant will be an appropriate fit for our needs.

Q. What is the next step in the process?

A. Once we know what our load and reserve requirements are, we must select the appropriate capacity resource. Mr. Pope has described how we determined what our reasonable alternative choices were for Gulf Power to add capacity, how we developed cost estimates for those alternatives, and how we eventually came to the decision that our best self-build option was the Smith combined cycle unit.

Q. Did the plans of other utilities offer you any confirmation that you had come to the right choice?
A. Yes. Other utilities needing capacity are adding the same type of combined cycle capacity as we are proposing, primarily for the economics and efficiencies it offers the customers who use the electricity.

Q. What was the result of Gulf's analysis?
A. As Mr. Pope described, the 540 MW combined cycle facility at Smith Plant was the most cost-effective self-build alternative. It is a good match for the amount of capacity needed. The unit has an excellent heat rate. Gas is a good, economical fuel choice in today's energy market, with relatively lower associated environmental costs. And, most importantly of all, it resulted in a significantly lower cost than any other alternative.

Q. After Gulf determined that the Smith combined cycle project was the best internal choice, how did it proceed?

A. We prepared a Request For Proposals (RFP) to test the market for a long term power purchase. Such a market test is a reasonable way to determine if your project is the most cost-effective. So, we prepared the RFP, advertised it in state newspapers and national industry magazines, and sent unsolicited copies to approximately 100 potential respondents.

Q. What was the result of Gulf's analysis of the responses as compared to your self-build option?

A. Witness Maria Burke has covered in detail how the proposed facility at Smith Plant has an NPV savings to our customers of over $90 million over the 20-year evaluation period compared to the best offer received in response to the RFP. With this overwhelming economic advantage, Smith Unit 3 was clearly the Company's most cost-effective alternative.

Q. What would the consequences be if the Commission did not find a need for Smith Unit 3?

A. As mentioned in Section 3.4.4 of the Need Study, recent inquiries in the purchased power market have resulted in fewer and more expensive offers for capacity and energy. Gulf has demonstrated through steps taken to date that its selection of Smith Unit 3 is the most cost-effective alternative available for the Company to meet its customers' load requirements beginning in 2002. Even with some minor delays, Gulf believes that it can achieve a summer 2002 in-service date for Smith Unit 3 in order to prevent having to use this high-priced purchased power. However, if there is a long delay of Smith Unit 3 that prevents meeting the June 2002 in-service date, at a minimum Gulf's customers will pay more for their electrical energy than necessary. The Company is also concerned with the possibility that without this unit's timely installation, which helps support Southern system reserves, there are additional reliability issues that could affect customer service.

Q. What, then, is Gulf asking of this Commission?

A. We are asking for a prompt certification of the need for Smith Unit 3 so we may proceed with the many remaining steps necessary to get this capacity installed for our customers' 2002 requirements.

We have demonstrated clearly that we need this additional capacity for our customers' needs in 2002. We have developed a quality load forecast that consistently gives good results. We have examined reasonable generating alternatives and determined that the best self-build candidate for our future generation needs is Smith Unit 3.

We have gone through the formal RFP process to determine the market economics of long-term power purchases as opposed to our own construction, performed a rigorous economic analysis, and demonstrated that Smith Unit 3 is a clear winner over any other available alternative. We ask the Commission to certify our need as soon as practicable.

Q. Does this conclude your testimony?
A. Yes.

Q **(By Mr. Melson)** And you had no exhibits attached to your direct testimony; is that correct?

A Correct.

Q You are sponsoring, are you not, Chapters 1, 2, Section 9.4, and Appendix A of the need study that's previously been identified as Exhibit 1?

A Yes.

Q And do you have any changes or corrections to your portions of that document?

A No.

Q Mr. Howell, could you briefly summarize your testimony?

A I'll do it briefly.

Good afternoon, Commissioners. You have heard our case. We believe we have met your regulatory standard to establish our need for Smith 3. By 2002 when Gulf plans to have the capacity in service, we will need approximately 75% of the maximum capability of the unit.

Without the unit, we have negative generation reserves and we have reliability problems that our customers will face. We feel like we have done what is required to establish the need. We have demonstrated that our load forecasting process is adequate for planning purposes. It uses state-of-the-art models. It gives good results. Our service territory continues to grow, and we need more electricity to serve this growing number of customers.

Gulf has performed a reasonable screening of all the alternatives available to us. We have looked at all the options to meet our growing load. Our self-build analysis determined that Smith 3 was the clear winner. It will use gas, a clean, relatively clean, burning fuel. The combined cycle technology which we propose has a high efficiency that is unavailable with any other generation alternative.

To ensure that our customers got the best deal, we issued an RFP. We tested the market to see if we could buy it cheaper than we could build it ourselves. We've done that. We've done a thorough cost-effectiveness analysis of it, and our unit is easily the winner.

What do we ask? We ask that you grant our request for a prompt approval of our generating unit so that we can complete all the steps necessary to get it in service by the summer of 2002.

That completes my summary.

CHAIRMAN GARCIA: Okay.

Q **(By Mr. Melson)** Mr. Howell, I've got a couple of questions for you to follow up on things that have been asked of other witnesses today.

From your perspective, has Gulf made a sound decision in deciding that backup fuel is unnecessary for Smith Unit 3?

A Yes, I believe we have.

And one particular thing, Commissioner Clark, that you asked was were we recommending, perhaps, that it was not a good policy decision for backup fuel.

And I think Gulf would like to make a clear distinction between a policy for maybe generating units in south Florida where many, many generating units are served off of a single pipeline and there is a disruption, as was evidenced by the problem at Perry, as opposed to Gulf Power.

We are asking for just one generating unit at the Smith plant right now on its own lateral. If we were asking for a number of generating units, then clearly I think we would evaluate the economics of a backup fuel supply.

COMMISSIONER CLARK: Mr. Howell, I'm satisfied that that question was answered. The indication to me was because of where -- the other fuel available to you in your interconnection, it doesn't make sense to do --

WITNESS HOWELL: Okay.

COMMISSIONER CLARK: -- the backup fuel.

WITNESS HOWELL: Okay. Let me go ahead and just comment on one other thing about that.

We certainly would have evaluated the benefits of the backup fuel if we felt like there was any chance at all that would be an economic issue, but the reliability of gas pipelines, I think we all know they say like once in 20 years you're going to have a problem like that.

In the 20-plus years I've been involved in system planning, it's the only one I have heard of. It is a very low probability event. And the fact that a steam turbine outage would take the unit out anyway, we have processed all that -- all of that through our economics and determined that it's really not worth the backup fuel.

Q **(By Mr. Melson)** And one other question, Mr. Howell.

Ms. Burke testified that her economic evaluations looked at system-wide fuel savings, if you will, on the Southern system. How can we be sure that when the project is evaluated on that basis that that system-wide fuel savings will actually be experienced by Gulf's customers?

A Well, for sure we cannot say with 100 percent certainty that all of those savings go to Gulf's customers. But I will tell you that I would say between 90 and 100% of those, maybe 95 and 100% of those, go to Gulf's customers.

And the reason is, the way we operate the system, we dispatch the units on an economic basis, and right now if we are buying or selling, we sell within the pool at our system marginal cost. So if Gulf is able to -- if it's in a buying mode, if it's able to generate with this lower cost energy rather than buying at system lambda, all those savings go to Gulf's customers. We don't have to pay system lambda.

And if we are in a selling mode, then the additional megawatt hours that this unit generates we can then sell at the difference between the system lambda and that unit's dispatch cost, and we get to keep all of that. And that's the way she ran her analysis. It was what happens to the total fuel cost on the system.

So the fact that we dispatch the units on an economic basis, every company gets to keep the lowest cost energy for its customers and we buy and sell at system lambda, you'd be hard-pressed to say that all those fuel savings don't go to your customers.

MR. MELSON: Mr. Howell is available for cross.

MS. KAMARAS: No questions.

MS. JAYE: Staff has no questions.

CHAIRMAN GARCIA: Commissioners? Redirect? You don't have any. All right.

(Witness Howell excused.)

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MR. MELSON: And at this point, Chairman Garcia, I would move Exhibit 1, which is the need study that's now -- every piece of that has now been sponsored by the appropriate witness.

CHAIRMAN GARCIA: There being no objection, show it into the record as admitted.

(Exhibit 1 received in evidence.)

CHAIRMAN GARCIA: Anything else? Commissioner Deason stated -- I wasn't aware of it -- that you wanted us to make a decision, bench decision, on this today.

COMMISSIONER DEASON: It is in the prehearing order that this possibility exists, and the parties were put on notice that if the Commission wanted to entertain the possibility of a bench decision, the parties were put on notice that they need to be prepared to conduct a closing argument in lieu of filing briefs; but there was no decision made whether there would or would not be a bench decision.

CHAIRMAN GARCIA: Would Staff feel comfortable making a recommendation?

MS. JAYE: Yes, Chairman Garcia; Staff is prepared to make an oral recommendation at this point.

CHAIRMAN GARCIA: All right. Commissioners, the only thing is I have a problem -- he's at a conference call.

(Discussion off the record between Commissioners.)

CHAIRMAN GARCIA: Let's do this. You organize your thoughts.

Do you want to make a --

MR. MELSON: I'd like to make a brief closing argument. It takes about five minutes.

CHAIRMAN GARCIA: Why don't you do that now so they can think about that and then they can make their recommendation, and then we're all finished up and all we require is a vote, if Commissioner Jacobs is willing to vote with us on this.

MR. MELSON: Commissioners, I'm going to urge in closing that you should vote to approve a determination of need for Smith Unit 3.

As you all are aware, Section 403.519

establishes four factors that you must take into account in making your determination, and we believe that the testimony you've heard today and the written evidence that's been admitted in this case supports an affirmative finding on each of those four statutory factors. I'm going to take them one by one.

First: "Has Gulf demonstrated there's a need for Smith Unit 3 when you take into account the need for electric system reliability and integrity?"

Our answer to that is absolutely yes. The evidence shows that without Smith Unit 3, Gulf's reserve margin would dip to a negative 6.3% in 2002. With the unit, we'll have adequate reserves to ensure the continuing reliability of Gulf's electric system when its existing purchase contracts expire in 2002.

The evidence also shows that Gulf has now arranged a firm gas transportation for the project that will support the reliable operation of the unit.

There were questions today about Gulf's decision not to use -- not to provide a backup fuel for the unit. We believe when you weigh all that evidence, when you look at the amount of coal on Southern's system, when you look at the inter-ties Southern has, when you look at the fact that Smith 3 is the only unit at this site relying on natural gas, and when you look at the fact that we've got a firm gas transportation contract and take all those into account, you should conclude that this unit is reliable without the need for a backup fuel.

COMMISSIONER CLARK: Are you going to add that it's also environmentally better?

MR. MELSON: It's environmentally better, and it enables us to get it permitted in the time and fashion. Thank you. This is part of my closing that I've actually done on the fly today. (Laughter.)

And the evidence also shows, Commissioner, that building the unit in the Panama City area balances the transmission and generation on Gulf's system and contributes to the integrity of the electric system, which is the other piece of that first test.

The second statutory factor: "Has Gulf demonstrated that there is a need for the Smith 3 when you take into account the need for adequate electricity at a reasonable cost?"

Again, we think absolutely we have. Gulf has submitted a high quality load forecast. It shows that Gulf needs at least 427 megawatts of additional resources to achieve its target reserve margin in the summer of 2002.

If you've got any question about whether that reserve margin ought to be higher, if it were higher, it would only enhance the need for the unit, not detract from it.

The evidence shows that Smith Unit 3 is a highly efficient combined cycle design that will provide adequate electricity to meet the needs of Gulf's customers, and the cost is significantly lower than any of the other alternatives.

The third statutory factor: "Has Gulf demonstrated that Smith Unit 3 is the most cost-effective alternative available?"

Again, the answer is absolutely yes. When it became clear that by the 2002 time frame, purchased power was going to be expensive and scarce, Gulf surveyed the waterfront for available self-build options and identified Smith Unit 3 as the best self-build alternative.

Following that initial identification, Gulf issued an RFP which sought outside alternatives to the unit. The evidence shows that process was conducted fairly and honestly in full compliance with the Commission's rules.

And unlike some other cases you've had, you don't have any intervenors here representing disappointed bidders. I think that tells you something about the quality of Gulf's process.

As Ms. Burke described, the evaluation of Smith Unit 3 and those alternatives took into account all the appropriate cost factors; capital costs, O&M costs, fuel costs, system fuel savings, transmission costs, transmission loss savings. And it's the sum of all of those that is expressed in her number that says on a dollar-per-kilowatt, net present value basis Smith Unit 3 comes in at $274 a kW compared to 496 per kW for the next best alternative.

Now, that's a little different type of way of expressing the results that you're accustomed to hearing in some other need cases. Staff asked us to do an analysis that was more in line with what they've seen in the past. And the result of that was shown on Pages 117 and 18, I believe, of the Exhibit 7, which showed the Smith Unit 3 is $121 million better than the next best alternative using the analysis that Staff asked us to conduct.

So no matter whose methodology you decide is right, the answer is clear; Smith Unit 3 is by far and away the most cost-effective alternative.

The fourth and last statutory factor: "Has Gulf demonstrated that there are not any conservation measures taken by or reasonably available to it that would enable the unit to be deferred?"

The evidence shows that Gulf has got existing conservation programs that have already reduced its summer peak demand by 244 megawatts in 1997. The testimony shows that by 2002 when Smith Unit 3 is needed, that demand reduction will have increased 365 megawatts.

There's no way that Gulf can reasonably add another 427 megawatts of conservation on top of the 365 and avoid the need for this unit. Gulf has acted responsibly in the conservation arena, and even with those savings, this unit is clearly needed.

In summary, Gulf has done a good job. They've done a thorough analysis. They've answered a lot of interrogatories and document production requests. This has been looked at by your Staff. You've got a lot of information before you in the record, and we believe that we've proved up every statutory element.

So we're asking you now to find that Gulf has a need for 427 megawatts of capacity by 2002 and that Smith Unit 3 at 574 megawatts is the best, most cost-effective way to meet that need.

CHAIRMAN GARCIA: All right. Thank you, Mr. Melson.

Staff, are you ready to make a recommendation?

I'm sorry, Ms. Kamaras. You've been so quiet.

MS. KAMARAS: LEAF has no objection, with the Commission's approval, of the need for this case.

When we entered into this case we had a number of questions concerning the need. Most of those questions have been answered by Gulf, either through interrogatories or through informal discussions.

We have some remaining questions relating to some of the environmental aspects, but that's not -- (inaudible) --

(Court reporter asked for clarification.)

MS. KAMARAS: So LEAF basically has no objection to your approving the plant at this time.

CHAIRMAN GARCIA: Thank you. Staff?

MR. HAFF: Yes. I'm Michael Haff of the Commission Staff.

In general, Staff recommends that the Commission grant Gulf Power Company's petition to determine the need for the proposed Smith Unit 3. Gulf's proposed unit will contribute to the provision of electric system reliability and integrity as stated in Section 403.519, Florida Statutes.

A large part of Gulf's existing generating capacity comes from its part ownership of units outside its service territory. Much of the remaining capacity on Gulf's system comes from the Crist units located in the western part of the service territory. Thus, a generation load mismatch or imbalance currently exists in the Panama City region.

All responses to Gulf's request for proposals contain projects requiring substantial transmission system additions and upgrades to supply their capacity to the Panama City region. The addition of Smith Unit 3 will minimize the number and cost of transmission system upgrades and new construction required.

Currently there are no plans for a backup fuel source for Smith Unit 3. Gulf believes that the parties to its natural gas contract will guarantee firm natural gas capacity sufficient to avoid the need for backup fuel. Further, if natural gas supplied to the plant is interrupted, Gulf's reliance on the Southern Company system should not be materially affected, because Southern's system has very little natural gas. It's primarily coal and nuclear-fired.

As an aside to this subject, because Gulf has not performed a cost benefit analysis of not installing backup fuel, Gulf should be made aware that any future purchased power costs associated with a natural gas fuel interruption will be reviewed for prudence at subsequent fuel adjustment proceedings. In other words, because of a lack of analysis, the prudence of future cost recovery of dollars associated with fuel supply interruptions will be investigated if and when they occur.

COMMISSIONER JACOBS: Do we know if there were escalators in their contract or not; firm contract?

MR. STONE: There are none. It is fixed; 20 years on transportation.

MR. HAFF: Staff would also ask for the Commission's permission to open a rulemaking docket to explore the policy of dual fuel capability for future power plants.

The need for adequate electricity at a reasonable cost: Gulf's proposed unit will contribute to the provision of adequate electricity at a reasonable cost, as stated in the 403.519, Florida Statutes.

Gulf has incorporated Southern's Company's

13.5% system reserve margin as its planning criterion. This criterion resulted from a study which compared the trade-off between the customers' cost of outages and the Southern System's cost to add peaking capacity to practically eliminate those outages.

Gulf's summer reserve margin in 2001, prior to adding Smith Unit 3, is forecasted to be around 1.4%. After the addition of Smith Unit 3, the 2002 summer peak -- or summer reserve margin is forecasted to be 17.6%. Staff believes that a 13.5% criterion is reasonable for Southern Company since the system has a low percentage of nonfirm load and can import over 5700 megawatts through nine separate utility interconnections.

We heard today that Southern is considering reevaluating its reserve margin criterion. If it were -- returned back to 15%, the magnitude of Gulf's capacity need in 2002 will even been greater than is shown now, and Smith Unit 3 will still satisfy this need.

Gulf's load forecast appears to be reasonable. Gulf uses state-of-the-art computer models to forecast load and energy consumption. Gulf presents its load forecast as a net of demand savings from conservation programs, which means that the load forecast used has already incorporated savings from conservation and demand-side programs.

The average forecast error in Gulf's load forecast over the last five years has been a relatively low 1.19%. Based on Gulf's load forecast and its reserve margin criterion, Gulf has identified a need for at least 427 megawatts of additional capacity in the year 2002. The proposed Smith Unit 3 will meet Gulf's need for additional capacity.

Gulf's proposed unit is an advanced combined cycle unit with a rated summer capacity of 574 megawatts. Its installed capital cost is approximately $197 million, or $343 per kW installed cost. This cost is reasonable and is in line with the cost of combined cycle units recently approved by this Commission for other utilities.

Gulf has demonstrated that the proposed Smith Unit 3 is the most cost-effective alternative available as required by Section 403.519, Florida Statutes.

Pursuant to the Commission's bidding rule, Rule 25-22.082, Florida Administrative Code, Gulf issued a request for proposals for capacity alternatives to Smith Unit 3. Staff believes that Southern Company's subsequent's analyses of RFP responses and Gulf's self-build option was performed on a consistent basis.

This analysis included an evaluation of the cost of connecting each self-build option and RFP project to Gulf's transmission system. Staff believes that Gulf adequately explored and incorporated the cost of such interconnections for each proposal.

The cost-effective analysis also included an evaluation of the cost to connect each self-build and RFP project to a natural gas transmission system. Gulf just signed a gas supply contract for transportation as of last Friday. Gulf received four responses to an RFP to supply gas to the project. Southern Company in its evaluation was conservative by using the most costly of the four in its cost-effectiveness evaluation for Smith Unit 3.

Staff believes that the fuel price forecasts used by Gulf in its cost-effectiveness evaluation are reasonable. Gulf made reasonable site-specific adjustments to the forecast to account for location differences among the RFP projects.

Staff believes that the financial assumptions used by Gulf in its cost-effectiveness analyses are reasonable. These financial assumptions were uniformly applied by Gulf in its evaluation of self-build options and RFP projects.

Incorporating all costs associated with unit construction, transmission interconnection, and gas supply, Southern Company found that Smith Unit 3 was the most cost-effective available to Gulf. Southern uses a relative ranking system to determine cost-effectiveness of resource alternatives. This ranking is given in dollars per kW, but differs from installed cost.

Southern takes the total network element present value cost of the project over its lifetime. These costs include capital, operations and maintenance, transmission, fuel, and other available costs and divides by the size of the unit. Using Southern's dollar per kW relative ranking system, Smith Unit 3 is substantially the most cost-effective alternative available.

The Commission has traditionally determined the cost-effectiveness of a proposed power plant based on a total dollar, cumulative present worth revenue requirements basis. On this basis, Smith Unit 3 offers savings of approximately $121 million over the next best alternative.

In summary, Gulf's analysis of self-build and RFP projects resulted in Gulf selecting the most cost-effective alternative available in choosing Smith Unit 3.

There are no conservation measures available to Gulf which would mitigate the need for the proposed unit. Gulf's load forecast incorporates the demand savings from its existing and proposed conservation measures. Gulf's need for at least 427 megawatts in the year 2002 is net of conservation program savings.

In summary, based on the resolution of the factual issues discussed today, Staff recommends that the Commission grant Gulf Power's petition to determine the need for the proposed Smith Unit 3.

CHAIRMAN GARCIA: Commissioners?

COMMISSIONER DEASON: I would move adoption of Staff's recommendation.

COMMISSIONER CLARK: Let me ask a few questions.

With respect to the rulemaking, I don't think -- if Staff thinks we should do rules -- Staff -- I'm not sure we need to do that.

CHAIRMAN GARCIA: I agree.

COMMISSIONER DEASON: I have no problem with that. That can be done -- it doesn't have to be part of this need determination.

COMMISSIONER CLARK: With respect to the --

the fuel, when were you looking at the fact that they don't have backup fuel, is what you're saying is for planning purposes it appears that not providing for backup fuel is appropriate, but it has to be constantly reviewed by the company to ensure that it continues to be the best way to prepare their system for outages, and should there be an outage occurred by the interruption of the natural gas supply to this plant, we would look at whether or not it was prudent to have continued the policy of not having backup fuel at that plant? Is that correct?

MR. HAFF: That's correct.

COMMISSIONER CLARK: Okay. Then I'm prepared to agree with the motion.

CHAIRMAN GARCIA: All right. Me, too. I also wanted to ask, we are in no way agreeing to their reserve margin of 13-some percent? Because I'd rather not do it in this docket. I don't feel comfortable. I know we recognize that's what they have. I'm not saying that's good or bad.

COMMISSIONER CLARK: A 15 and a 13 --

CHAIRMAN GARCIA: Now, that -- Staff went further from there. But I don't in any way want to adopt their criteria of 13.5%.

MS. JAYE: I do not --

CHAIRMAN GARCIA: And I want to make sure that we didn't say that in --

MS. JAYE: I understand the concern, Mr. Chairman. However, I do not believe that that is necessary to actually reach the adoption of that reserve margin criteria in answering the statutory elements that are needed to be answered in this docket. And I believe even with taking that out, Staff's analysis would not change.

CHAIRMAN GARCIA: Would the motion mind if we took that discussion out?

COMMISSIONER DEASON: I have no objection to that. I guess there is a point of clarification, though; and it may be a fine distinction, but I think that we need to clarify.

I understood Staff's recommendation to be that in future fuel adjustment proceedings, if there is a curtailment of natural gas supply to this unit and there has to be replacement power that's at an incremental cost, that there has to be some justification shown at that time, not just justification that in the future they may need to add a backup supply of fuel.

And I understand Commissioner Clark's comments to be that, well, there wouldn't be a review on the existing costs; there would just be a forward-looking review if there needs to be --

COMMISSIONER CLARK: No. At that time we would again review whether it was prudent for them not to have had that available.

COMMISSIONER DEASON: Right. Okay. Very well.

CHAIRMAN GARCIA: We have a motion and a second. All those in favor, signify by saying aye.

(Simultaneous votes.)

CHAIRMAN GARCIA: Aye.

COMMISSIONER CLARK: Aye.

COMMISSIONER JACOBS: Aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER JOHNSON: Aye.

CHAIRMAN GARCIA: Thank you very much.

MS. JAYE: I'm sorry Mr. Chairman. We need to close the docket. That's the last issue.

UNIDENTIFIED SPEAKER: So moved.

COMMISSIONER JACOBS: Second.

CHAIRMAN GARCIA: There being no objection, the docket is closed.

(Thereupon, the hearing concluded at 3:45 p.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTERS
COUNTY OF LEON)

We, JOY KELLY, CSR, RPR, H. RUTHE POTAMI, CSR, RPR, and KIMBERLY K. BERENS, CSR, RPR, FPSC Commission Reporters;

DO HEREBY CERTIFY that the Hearing in Docket No. 990325-EI was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed by us; and that this transcript, consisting of 242 pages, constitutes a true transcription of our notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

DATED this 10th day of June, 1999.

Joy Kelly

JOY KELLY, CSR, RPR
Chief Bureau of Reporting
(850) 413-6732

H. Ruthe Potami

H. RUTHE POTAMI, CSR, RPR
FPSC Commission Reporter

Kimberly K. Berens

KIMBERLY K. BERENS, CSR, RPR
FPSC Commission Reporter

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company to Determine Need for Proposed Electrical Power Plant in Bay County, Florida	Docket No.: 990325-EI Filed: May 17, 1999

SUPPLEMENT TO PETITION TO DETERMINE NEED
FOR ELECTRICAL POWER PLANT

Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned attorneys, hereby supplements the Company's petition to the Florida Public Service Commission ("Commission") pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code asking the Commission to determine the need for the Company's proposed electrical power plant, and to file its order making that determination with the Department of Environmental Protection ("DEP") pursuant to Section 403.507(2)(a)(2), F.S.

The Company's petition and supporting documentation, as filed on March 15, 1999, referred to the proposed electrical power plant as a 540 MW combined cycle generating facility, to be constructed at the existing Lansing Smith generating plant site located in Bay County, Florida. The new unit, to be known as Smith Unit 3, consists of two "F" class combustion turbine generators and two heat recovery steam generators that will drive a single steam turbine generator. As noted in the attached Supplement to Gulf Power Company Need Study and the supplemental direct testimony of Gulf's witnesses R. G. Moore, W. F. Pope and M. J. Burke filed contemporaneously with this supplement to the Company's petition to determine need for electrical power plant, Gulf has continued to refine the engineering design and cost estimate for Smith Unit 3 in an effort to achieve the best overall value for the proposed electrical power plant.

As a result of design changes identified through this ongoing engineering process, the proposed Smith Unit 3 is now more appropriately referred to as a 574 MW combined cycle generating facility.

WHEREFORE, Gulf Power Company respectfully requests that the Florida Public Service Commission determine that there is a need for the proposed electrical power plant described in this supplement to the Company's petition to determine need for electrical power plant, and that the Commission file its order making such determination with the DEP pursuant to Section 403.507(2)(a)2., F.S.

RESPECTFULLY SUBMITTED this 17th day of May, 1999.

By:__________________________

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SUPPLEMENT TO GULF POWER COMPANY NEED STUDY

Since the filing of Gulf Power Company's Need Study on March 15, 1999, Gulf has continued to refine the engineering design and cost estimate for Smith Unit 3 in an effort to achieve the overall best value.

As a result of design changes identified through this ongoing engineering process, Gulf has been able to increase the summer peak capacity of the unit from approximately 540 MW to approximately 574 MW. This increase is accomplished by adding the capability to produce a higher mass steam flow through the steam turbine generator. The changes associated with this 6.3% increase in maximum unit capability result in a slight reduction in the average annual output of the unit, from 521 MW to 519 MW, and a slight increase in the average annual heat rate for the unit from 6,741 Btu/KWH to 6,761 Btu/KWH.

The total nominal cost estimate for the Smith Unit 3 has increased by $9,670,000, or 5.2%, to $196,922,000. On a per KW basis, the total nominal cost has decreased from approximately $347/KW to approximately $343/KW.

To confirm that the cost-effectiveness of the project has been improved on a net present value (NPV) of total cost basis, Gulf has analyzed the total revenue requirements associated with the larger unit using the same PROVIEW evaluation methodology that was used in the previous ranking of Smith Unit 3 and the RFP alternatives. The results of this study are presented in the attached table which updates the information previously provided in Table 8-2 of the Need Study.

This updated analysis shows that the evaluated NPV cost of Smith Unit 3 has decreased from $279/KW to $274/KW in 2002 dollars. This indicates that the incremental MWs resulting from the design change are a cost-effective capacity resource.

Based on this analysis, Gulf has concluded that the design changes to Smith Unit 3 represent a cost-effective means of providing 34 MW of additional capacity under summer peak conditions. Gulf therefore requests the Commission to determine a need for 574 MW of capacity and to find that Smith Unit 3 is the most cost-effective means of meeting that need.

TABLE 8-2 (Revised 5/17/99)

Gulf RFP 2002 Supply

Relative Ranking - Detailed Evaluation

Rank	MW	Bidder	NPV Total Cost $/kW (2002$)
1	574	Smith Unit 3	274
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	351.5	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company)
to determine need for proposed)
electrical power plant in Bay County)
____________________________________)

Docket No. 990325-EI

Certificate of Service

I HEREBY CERTIFY that a copy of the foregoing has been furnished this 17th day of May 1999 by U.S. Mail or hand delivery to the following:

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Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: Robert G. Moore
Exhibit 2 (RGM-1)
Schedule 1

SMITH UNIT 3 OPERATING CHARACTERISTICS

Forced outage rate	3.4%
Scheduled maintenance outage (Avg.)	2 wks/yr
Equivalent availability	92%
Expected average capacity factor	62%
Fuel consumption (full load)	3,900 MMBtu/hr
Annual fixed O & M (98$)	$2.84/KW-yr.
Variable O & M (98$)	$1.89/mWh

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990325-EI EXHIBIT NO. 2
COMPANY/
WITNESS: Moore
DATE: 6-7-99

INSTALLED COST ESTIMATE FOR SMITH UNIT 3

DESCRIPTION:	AMOUNT (2002$)
Indirects	$ 23,661,966
Site, General	2,701,846
Steam Generator Area	36,741,570
Turbine & Generator Area	91,143,505
Fuel Facilities (metering only)	856,111
Plant Water Systems	13,443,351
Electrical Distribution & Switchyard	12,177,183
Plant Instrumentation & Controls	2,591,303
Other	3,935,190
TOTAL	$187,252,025

Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: Robert G. Moore
Exhibit 3 (RGM-2)
Schedule 3

INSTALLED COST ESTIMATE FOR SMITH UNIT 3

DESCRIPTION:	AMOUNT (2002$)
Indirects	$ 25,661,966
Site, General	6,701,846
Heat Recovery Steam Generator Area	39,741,570
Turbine & Generator Area	91,143,505
Fuel Facilities (metering only)	856,111
Plant Water Systems	13,443,351
Electrical Distribution & Switchyard	12,847,183
Plant Instrumentation & Controls	2,591,303
Other	3,936,065
TOTAL	$196,922,900

Florida Public Service Commission
Docket No. 990325-EI
Gulf Power Company
Witnesses: Margaret D. Neyman
Michael J. Marler
Exhibit No. 4 (MDN/MJM-1)
Schedule 1

History and Forecast Summary							
	1989 History	1998 History	2003 Forecast	2008 Forecast	CAAG[1] 1989-1998	CAAG[1] 1998-2003	CAAG[1] 1998-2008
Population	662,784	810,649	891,566	960,867	2.3%	1.9%	1.7%
Residential Customers	250,038	304,413	337,784	367,016	2.2%	2.1%	1.9%
Customer Gains					54,375	33,371	62,603
Kwh / Customer	13,173	14,577	14,677	14,995	1.1%	0.1%	0.3%
Energy (GWh)	3,294	4,438	4,958	5,503	3.4%	2.2%	2.2%
Commercial Customers	33,500	45,510	51,208	55,836	3.5%	2.4%	2.1%
Kwh / Customer	64,761	68,379	68,275	69,507	0.6%	0.0%	0.2%
Energy (GWh)	2,169	3,112	3,496	3,881	4.1%	2.4%	2.2%
Net Energy for Load (GWh)	8,378	10,402	11,658	12,661	2.4%	2.3%	2.0%
Summer Peak Demand (MW)	1,698	2,154	2,280	2,466	2.7%	1.1%	1.4%
Winter Peak Demand (MW)	1,554	1,692	2,139	2,258	0.9%	4.8%	2.9%
Load Factor (%)	56.3%	55.1%	58.4%	58.6%			

NOTES: [1] CAAG stands for Compound Average Annual Growth

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990325-EI EXHIBIT NO. 4
COMPANY/
WITNESS: Neyman/ Marler
DATE: 6-7-99

Florida Public Service Commission
Docket No. 990325-EI
Gulf Power Company
Witnesses: Margaret D. Neyman
Michael J. Marler
Exhibit No.______(MDN/MJM-1)
Schedule 2

Demand Side Management Programs

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Building
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

Florida Public Service Commission
Docket No. 990325-EI
Gulf Power Company
Witnesses: Margaret D. Neyman
Michael J. Marler
Exhibit No.______(MDN/MJM-1)
Schedule 3

CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	Summer Peak (MW)			Winter Peak (MW)			Net Energy for Load (GWH)		
	Existing	New	Total	Existing	New	Total	Existing	New	Total
1997	214	30	244	263	6	269	514	9	523
2002	252	112	365	295	128	423	573	77	650
2008	290	199	489	335	256	590	625	146	770

Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: William F. Pope
Exhibit No. 5 (WFP-1)
Schedule 1

SUMMARY OF ECONOMIC ANALYSIS

SELF-BUILD ALTERNATIVE	NET PRESENT VALUE OF COSTS (98$ MIL)
Smith Unit 3	117.1
Smith Combustion Turbine	158.5
Daniel Combined Cycle	236.7
Mulat Tower (cogeneration)	239.0

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990325-EI EXHIBIT NO. 5
COMPANY/
WITNESS: Pope
DATE: 6-7-99

Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: William F. Pope
Exhibit No. _____ (WFP-1)
Schedule 2

GULF'S FUTURE RESERVES BEGINNING IN 2002 WITH THE ADDITION OF SMITH UNIT 3

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY[1] (MW)	CAPACITY ADDITION (MW)	ENDING CAPACITY (MW)	PERCENT
RESERVES					
2002	2,265	2,123	540	2,663	17.6%
2003	2,280	2,663	0	2,663	16.8%
2004	2,309	2,663	0	2,663	15.3%
2005	2,347	2,663	-19	2,644	12.7%
2006	2,383	2,644	0	2,644	11.0%
2007	2,425	2,640	148	2,788	15.0%
2008	2,466	2,784	0	2,784	12.9%

Footnotes: [1] The beginning capacity figures have interruptible load embedded into them in the amounts of: 34 MW for 1999 - 2006, 30 MW for 2007, and 26 MW for 2008.

Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: William F. Pope
Exhibit No. 6 (WFP-2)
Schedule 3

GULF'S FUTURE RESERVES BEGINNING IN 2002 WITH THE ADDITION OF SMITH UNIT 3

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY (MW)[1]	CAPACITY ADDITION (MW)	ENDING CAPACITY (MW)	PERCENT RESERVES
2002	2,265	2,123	574	2,697	19.1%
2003	2,280	2,697	0	2,697	18.3%
2004	2,309	2,697	0	2,697	16.8%
2005	2,347	2,697	-19	2,678	14.1%
2006	2,383	2,678	0	2,678	12.4%
2007	2,425	2,674	148	2,822	16.4%
2008	2,466	2,818	0	2,818	14.3%

Footnotes: [1] The beginning capacity figures have interruptible load embedded into them in the amounts of: 34 MW for 1999 - 2006, 30 MW for 2007, and 26 MW for 2008.

EXHIBIT NO. ___________

Docket No: 990325-EI

Party: Gulf Power Company

Description: COMPOSITE EXHIBIT

(1) Gulf's Response to Staff Interrogatory Nos. 1-2, 4, 8, 16-25, 27, 32-35

(2) Gulf's Response to Staff Request for Production of Documents Nos. 17-19, 21c

(3) Late-filed Exhibit #3 from Deposition of William Pope

(4) Summary of Late-filed Exhibit #4 from Deposition of William Pope

(5) Transcript from Deposition of William Pope

(6) Transcript from Deposition of Maria Burke

(7) Transcript from Deposition of Michael Marler

Proffered By: Commission Staff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990325-EI EXHIBIT NO. 7
COMPANY/
WITNESS: FPSC Staff
DATE: 6-7-99

STAFF COMPOSITE EXHIBIT
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Gulf Power Company's Response to Staff Interrogatories

Gulf Power Company's Response to Staff Request for Production of Documents

Late-filed Deposition Exhibits

Deposition Transcripts

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990325-EI EXHIBIT NO. 8
COMPANY/
WITNESS: FPSC Staff
DATE 6-7-99

<u>CONFIDENTIAL</u>

REDACTED

EXHIBIT NO. 8

Docket No: 990325-EI

Party: Gulf Power Company

Description: COMPOSITE EXHIBIT

(1) Gulf's **<u>CONFIDENTIAL</u>** Response to Staff Interrogatory Nos. 1 & 17

(2) **<u>CONFIDENTIAL</u>** Late-filed Exhibit Nos. 1, 2, and 4 from Deposition of William Pope

Proffered By: Commission Staff

STAFF COMPOSITE EXHIBIT
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Florida Public Service Commission
Docket No. 990325-EI
Gulf Power Company
Witness: Maria Jeffers Burke
Exhibit No. 9 (MJB-1)
Schedule 1

Gulf Power Company

RFP Initial Screening Results

Summer Rating MW	Proposal	Location	NPV Total Cost $/kW (2002$)
500	Combined Cycle	Holmes County, FL	273.8
486	Combustion Turbine	Holmes County, FL	332.1
350	Family of Cogeneration Facilities	Mobile, AL and Santa Rosa County, FL	432.3
532	Combined Cycle	Hardee County, FL	565.2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990325-EI EXHIBIT NO 9
COMPANY/ WITNESS: Burke
DATE: 6-7-99

Florida Public Service Commission
Docket No. 990325-EI
Gulf Power Company
Witness: Maria Jeffers Burke
Exhibit No. ______(MJB-2)
Schedule 2

Gulf Power Company

RFP Relative Ranking – Detailed Evaluation

Rank	MW	Bidder	NPV Total Cost $/kW (2002$)
1	540	Smith Unit 3	279
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	350	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

Florida Public Service
Commission
Docket No. 990325-EI
Gulf Power Company
Witness: Maria Jeffers Burke
Exhibit No. 10 (MJB-3)
Schedule 3

Gulf Power Company

RFP Relative Ranking – Detailed Evaluation

Rank	MW	Bidder	NPV Total Cost $/kW (2002$)
1	540	Smith Unit 3	274
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	350	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990325-EI EXHIBIT NO 10
COMPANY/
WITNESS: Burke
DATE: 6-7-99

AFFIDAVIT

STATE OF ALABAMA	)	Docket No. 990325-EI
	)	
COUNTY OF JEFFERSON	)	

Before me the undersigned authority, personally appeared Maria Jeffers Burke, who being first duly sworn, deposes, and says that she is a Project Manager in the Generation Planning And Development of Southern Company Services, an Alabama corporation, that the foregoing is true and correct to the best of his knowledge, information, and belief. She is personally known to me.

Maria Jeffers Burke

Maria Jeffers Burke
Project Manager – SCS Generation Planning
And Development

Sworn to and subscribed before me this 13th day of May, 1999.

Priscilla K. Daly

Notary Public, State of Alabama at Large

NOTARY PUBLIC STATE OF ALABAMA AT LARGE.
MY COMMISSION EXPIRES: Feb. 7, 2001.
BONDED THRU NOTARY PUBLIC UNDERWRITERS.

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of MICHAEL J. MARLER; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 11th day of May, 1998.

Nancy S. Metzke

NANCY S. METZKE, RPR, CCR

CERTIFICATE OF DEPONENT

This is to certify that I, MICHAEL J. MARLER, have read the foregoing transcription of my testimony, Page 1 through 24, given on May 11, 1999, in Docket Number 990325-EI, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

____

MICHAEL J. MARLER

Sworn to and subscribed before me this
_______ day of ______________, 19_____
____
NOTARY PUBLIC
State of _____________________________
My Commission Expires:

257

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that MICHAEL J. MARLER personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 11th day of May, 1999.

Nancy S. Metzke

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE INC

ERRATA SHEET

DOCKET NUMBER 990325-EI
MICHAEL J. MARLER
MAY 11, 1999

don't want him to go out on a limb if it's something better left to her.

MS. JAYE: Okay. Certainly.

THE WITNESS: My experience with it has been strictly from an analysis of the load data and what type of demand response that we have seen actually occur, to the extent that I can expect those demand reductions to occur in the forecast period. Beyond that I can't speak.

MS. JAYE: We have no more questions.

MR. MELSON: No, I don't have any questions.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

same time period in the summer peak demand table.

Q Okay. Looking then at Footnote 2 on Table B-15, it appears that Gulf treats interruptable as a supply side resource. Is this also true of the Southern System?

A Yes, I believe so. I am not familiar with that though because I don't get involved in that aspect of the Southern System modeling. I develop the territorial load forecast and provide that to the system planners, and I also provide them with our interruptable amounts, and I identify that as not embedded in the demand side load forecast.

Q Okay.

A So that they can handle it appropriately.

Q Remaining with Table B-15 for a moment, Column 7, where it speaks of residential conservation. Is the GoodCents New Home conservation program represented there in Column 7?

A Yes.

Q Okay. Could you summarize Gulf's experience with the experimental real-time pricing pilot program?

MR. MELSON: I don't know whether this is within the scope of his testimony or more properly in the scope of Ms. Naman's (phonetics). They filed joint testimony, and she really deals with conservation issues. To the extent he knows, that's fine; but I energy forecasts under. Again, all of those individual resulting 87, 60 load shape projections are then summed together to build the total industrial demand forecast. A similar process occurs for wholesale, and all of these individual resulting load shapes are then summed together to model the total company, 87-, 60-hour demand forecast.

Q All right. I need to turn over to Tables B-15 and B-16 which are also in the need study.

A Okay.

Q I was wondering if you could explain why the Column 1 for the summer peak and the winter peak report different reference years.

A Well, they actually don't. Column 1 begins in 1989 and goes through 1998 on the summer peak, Table B-15. On the winter peak, Table B-16, the year is described as a dual number, '88-'89 through '97-'98. And, basically, that's because the actual winter peak period encompasses two different fiscal years. It begins in November and goes through March, and our actual winter peak demand is expected to occur in January typically.

So January of '89 would be the actual time in the forecast that the peak demand would occur in, and -- or generally '99 would be more appropriate, I guess. All the forecast years, January is the winter peak month. And so all of these years in this table actually do go for the would be the outputs from the REEPS model which comprise the heating and air conditioning, energy consumptions, water heating, things of that nature. Each of those energy forecasts are modeled under the appropriate end-use load shape to develop an 87-, 60-hour load shape forecast that are all summed together within the residential model itself and result in an 87-, 60-hour per year residential load forecast.

Similarly, the commercial demand forecast is developed feeding it all of the individual demand output energy projections for all of the building types, and within each building type the end-use consumptions for heating, air conditioning, cooking, water heating, et cetera. Each of those energy projections is modeled under its appropriate load shape, and the load shapes are then summed to build a total commercial demand forecast.

Within the industrial sector, each of the individual hand-build industrial customers are modeled in the energy forecast separately. Those energy projections are individually modeled where load data is available for the specific customers. Some of them are grouped into like categories, such as the oil and gas, or some of the more general military accounts possibly. And so in the industrial sector there's a lot of intensive individual load shape data that's utilized to model specific customer categories that we have identified here. Things like dry cleaners.

Q What economic factors would explain the increase of "miscellaneous" over the forecast period?

A Again, it would be the growth in commercial services to meet the needs of the growing population. All of that is part of the interactive model developed by RFA that encompasses the growth in residential population, commercial, building floor stock, as well as the industrial shipments in the industrial sector, and falls out, again, as part of the calibration process.

Q The next set of questions, we'll turn back to the need study itself. The first questions come from Page 94 of the study.

A Okay.

Q Does the hourly electric load model, or HELM, generate peak demand forecast using a neural network architecture?

A No, it does not.

Q How does it then develop the peak forecast?

A The HELM model uses load research, load shape data for all of the end uses that are modeled within our different long-term modeling. For instance, in the residential sector, the residential load shape would be developed in HELM by feeding it -- or the inputs to it to staff's Request for Production Number 7. I apologize. I'll give you a chance to turn there.

(WITNESS REVIEWED DOCUMENTS)

Q The question was what economic factors explain the increase of "other" over the forecast period?

A "Other" would be capturing the long-term economic indicators such as income growth, population growth, the basic increases in the base load usage patterns in the residential sector. The model development part of it goes through a calibration process, and the assumption portions that are not explainable in each of the other end uses is left in the "other" term. And so part of the driver is population, and the remaining drivers would be the economic indicators.

Q Turning now to the commercial electric sales forecast in that same request for production. Do electric sales to Pensacola NAS come under the heading of "offices?"

A No, our military sector is actually in the industrial forecast.

Q Okay. And looking again on the commercial page, what comes under the category of "miscellaneous?"

A "Miscellaneous" would cover a lot of the small commercial businesses such as gas stations, possibly. Right off the top of my head I'm having difficulty thinking of those, but it would not fall in these measured request, we'll honor it.

MS. JAYE: We'll just title this one parameter coefficients. Is that good enough? Okay. And I understand if there's some kind of a proprietary problem with EPRI and they cannot, you know, release that or whatever, just get back with us and we'll go from there.

MR. MELSON: Okay.

BY MS. JAYE (Continuing):

Q Does the forecast for air conditioning end-use sales represent a composite figure for both central air and wall units?

A Yes.

Q Okay. I was wondering if you could explain what comes under the category of "other" in the end-use sales forecast.

A "Other" would be the all-encompassing variables that capture all of the non-specifically modeled end uses, things like clock radios, all the other electrical loads within a residential that's non-heating and cooling, non-cooking, non-water heating type loads. It's basically the base load energy usage of a home. ✓

Q Okay. Do you know what economic factors explain the increase of "other" over the forecast period? This is the information that was provided, I believe, in response other words, a cooking load, for instance, would also cause additional cooling to take place and things of that nature, and these coefficients are from a nationally developed model that's provided by EPRI.

Q Would it be possible to get a late-filed deposition exhibit which gives these coefficients?

A I believe so. I'm not positive. I don't have direct access to those coefficients, but I can look and see, so subject to check.

MR. MELSON: Yeah, do you know whether -- and I don't know whether EPRI regards any of those as proprietary since they are interpreting the model.

THE WITNESS: I don't know either.

MR. MELSON: Why don't we identify it and we'll check, and if we can get them for you, we will; and if there's a reason that we either cannot get them from EPRI or there's a confidentiality concern, we'll give that to you as a response.

MS. JAYE: Okay.

MR. MELSON: Tell me again exactly what it is you want so I --

MS. JAYE: The parameter coefficients which were used for the multinomial logit appliance model.

MR. MELSON: Since half those words don't make any sense to me, if my witness understands the body heat and change the energy response equation slightly. The breakpoints, for instance, in commercial on heating degree hours and cooling degree hours for Gulf are 54 degree and 62 degrees as compared to the residential breakpoints of 65 and 70. That indicates that because of the body heat heating energy is not required in commercial buildings until you reach a much lower temperature than in a residential building. Similarly on cooling, because of the body heat, cooling energy is required much sooner than it would be in the residential sector.

Q Okay. Now we are going to go back to the need study. Turn to Page 87, if you will, please. I've got a couple of questions about this.

A Okay.

Q On Page 87, the need petition references a multinomial logit appliance model. Where in the petition are the model's parameter coefficients?

A The parameter coefficients for the model, these are developed by EPRI and are internal to the REEPS model. I don't have available to me the coefficients for the end use parameters specifically. The multinomial logit is a term to describe the interaction between each of the equations within the REEPS model, each of which tries to describe different end-use energy consumption and capture the interaction between these end-use energy variables. In dummy variables are merely picking up a little bit of an extra component that I guess can be considered similarly to a partial constant term during those months.

Q Turning now over to the commercial short-term energy model of the coefficients. I was wondering if you could provide an econometric interpretation of the coefficients for commercial heating degree days, commercial cooling degree days, commercial price in this model.

A Again, these are heating degree hours per billing day and cooling degree hours per billing day. Interpretation of the coefficients, the heating degree hours and cooling degree hours, as you can see, the sign on the coefficient is positive. This is an indication of the amount of additional energy sales that occur in that sector due to heating degree hours or cooling degree hours. The sign on the price term is negative, and this also indicates that as price increases the energy sales for that sector would decrease.

In this case the signs in front of the monthly dummy variables are negative for January, May, November, December, which are the only statistically significant monthly dummy variables that were available to the model. In commercial, the energy consumption characteristics are somewhat different from residential in that there's a lot of people, bodies in commercial buildings that contribute price?

A Could you please restate that?

Q Yes. There's a coefficient for the residential price, and I was wondering if the dummy variable tracks that in any way, if there is a relationship between the two.

A Well, all of the variables are interrelated because they all are trying to explain part of the variability in the data. Each of these monthly dummy variables is merely picking up a component of the energy consumption pattern that is above and beyond those that fall out normally through the heating and cooling degree hour variables and the price variables, meaning that, for instance, in January there's some extra energy consumption that takes place above and beyond that which is explained in, say, a more shoulder month as a result of a heating degree hour. That shoulder month being a month in transition from mild weather period, just beginning into the heating season where customers will be less likely to immediately turn on their heat in response to a particular temperature. Whereas, in January, they're more apt to already have their heating system on, and the electricity consumption for that same temperature would show up a little more intense than in the other months. Similarly, this happens in the summer months, and so these monthly heating degree hours, meaning that all of the hours in which the temperature is below 65 degrees is designated as a heating hour. And for cooling, Gulf uses a 70-degree breakpoint, meaning that all the hours in which the actual temperature is above 70 degrees is assumed to be a cooling hour with a dead band area between 65 and 70 in which neither heating nor cooling takes place.

Gulf transformed the heating degree hours and cooling degree hours to a per billing day basis to make a better fit with the model and put it on the same terms with the actual dependent variable, which is residential billed energy sales per billing day. The price variable shown here is a 12-month rolling average of real price for the residential sector.

Q Could you explain the economic rationale for including the six monthly dummy variables in this table?

A In development of my models, I look at all of the monthly dummy variables that are available in the software package. I include or leave in only those that offer statistically significant explanatory capabilities. In this case, January, June, July, August, September, and October were the only variables that remained in the model.

Q Okay. So Mr. Marler, would you say then that the dummy variable follows the coefficient on residential

Q So, Mr. Marler, in your opinion, income of the customer would have no explanatory effect or impact on sales of electricity?

A I can't answer its impact on the modeling capability. I just know that I've got over 98% of the variability explained with price and weather variables and don't -- I have never experimented with the income figures to see if it would add explanation enough.

Q Okay. I've got a few questions about the residential heating degree days and cooling degree days now. There's a page further on over in the same POD.

A Okay.

Q Could you provide an economic interpretation for the regression coefficients residential heating degree days and the residential cooling degree days, residential price and the residential short-term model that was provided?

A Yes, the variables that you see here, we actually use heating degree hours per billing day and cooling degree hours per billing day. These are defined as the results from analysis of actual hourly weather on a monthly basis looking at the 21 billing cycles that Gulf uses when it reads the meters, and the average number of billing days for those 21 cycles is divided into the total heating degree hours or cooling degree hours that result in that month. Gulf uses a 65-degree reference temperature for take place outside of the areas in which we actually provide service. Currently we still have some growth taking place in northern Escambia County, but beyond the mid to -- and into the long-term range, most of that growth starts taking place outside of the areas where we actually provide service.

Q The next series of questions comes from Gulf's response to the staff Request for Production of Documents Number 7. I'll give you a chance to turn there.

(WITNESS REVIEWS DOCUMENTS)

A Okay.

Q These questions have to do with the residential short-term energy model. I believe it's one of those pages that's appended.

A Okay.

Q In this particular model, the reported coefficients exclude an income variable. I'd like to understand why that variable was excluded.

A Well, the variable itself didn't -- I have never actually used it in the past. I was able to explain virtually all the model variance with price and weather variables, and the price response pretty much captures the ability of the customers to -- or willingness to pay a certain amount for electricity, and so I've never used an income variable because it wasn't necessary.

A Well, the purpose of the end-of-year data that's used by our district marketing personnel is primarily for development of the short-term customer projections, and we develop those by projecting first the annual expected customer additions, which is what we call gains; and the total number of customers in the projection can be built by adding those gains to the most recent actual annual number of customers. Those figures that we end up with are monthly number of customers from which you can calculate annual average number of customers or any other kind of customer statstics you're interested in.

The long-term models use annual average customers in their energy projection because they're an annual model basis; whereas, my short-term models are monthly models and require monthly number of customers.

Q If you would turn to the sheet provided with the response to staff's Request for Production Number 6. It's the title "Gulf B99 Long-term Customers" at the very top. The sheet looks like this (indicates).

A Okay.

Q Could you explain why the forecast ratio for Gulf-served residential customers to service area households, which is Column 5, declines after 2005?

A This is a reflection of Gulf's assumption that the majority of the long-term customer growth is going to reference is made to the Gulf economic model. I was wondering if you could summarize some of the basic equations used in this model and perhaps briefly discuss how frequently these forecasts are updated.

A My knowledge of this model is essentially similar to what I mentioned previously as we were discussing the previous tables. RFA, Regional Financial Associates, is our economic services provider and they model the Gulf-specific service area. They have two different methods. One models our internal economy, the businesses, industry, internal population growth; and it also models a competitive model with the reason surrounding our service area that takes into account the in-migration and out-migration of business and industrial goods and things of that nature. The two together comprise our total economic forecast, and they update this information annually.

Q I have a few questions now on Gulf's response to the staff's Request for Production of Documents Number 6. I'll give you a minute to turn there.

(WITNESS REVIEWED DOCUMENTS)

Q My first question is more or less just for my own education. Could you please explain why the residential and commercial customer projections use the end-of-year data as opposed to an annual average?

the annual population -- average annual population growth. Is this a weighted average for all eight Florida counties in Gulf's service territory, or just the three most populous ones?

A This would be all eight counties, and the average is for the ten-year period stated in the title there.

Q We do have a question about some of the information on Table 4-2. What is the average employment growth for Gulf Service territory from the years 1998 to 2008?

A The average employment growth?

Q Yes, sir.

A I would believe -- I believe that would be equivalent to the labor force growth figure. Error

Q Okay.

A Of 1.5%.

Q So the labor force growth would mirror the actual numbers of jobs and employment that would be available?

A Yes, I believe that's correct. Error

Q Okay. So numbers of workers would equal numbers of jobs?

A Yes, I believe so. I'm not directly involved in development of RFA's forecast, but this is one of their indicators that comes out of their economic projections.

Q Turning now to Page 29 of the need study. A forecast are the base rate prices from the previous year's budget forecast as contained in the financial model files. They are the results of the previous forecasts. Additionally, they contain the adders, such as fuel purchase power capacity cost, ECR, and ECCR adders that are from the most recent Southern Company Services fuel panel.

Q Mr. Marler, looking at the tables on Page 28, I've got a couple of questions. On Table 4-1 of the need petition, it looks as if one of the economic assumptions cited is the GDP growth, and my question is why wasn't consideration made for the gross state products? Because the two figures can differ.

A Well, these indicators in this table are national indicators, and they're just meant to be a summary of the overall economic outlook. The gross state product comes into play in RFA's economic forecast development. They model Gulf-specific service area, and their model is comprised of two modeling techniques. One looks at our in-service economy -- our in-service area economy and the expected growth within our in-service businesses, and the other modeling technique looks at the surrounding areas and models the competition with the surrounding areas; and that's how they develop their in-migration and out-migration estimates.

Q Looking at Table 4-2 now, I have a question about

Whereupon,

MICHAEL J. MARLER

was called as a witness by the FPSC Staff and, after being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. JAYE:

Q Nancy, would you please insert all the usual stipulations? Thank you.

Good morning, Mr. Marler.

A Good morning.

Q I have a few questions to ask you just as background. How long have you been with Gulf?

A I joined Gulf Power in January of 1982.

Q Okay. What positions have you held with the company?

A I began in the load research section as a load research engineer, and I transferred to the forecasting section in 1988, and I've been in forecasting since then.

Q Okay. We'll jump right in here, and I ask you to turn to Page 27 of the need study, the very last sentence which carries over to Page 28. The study here makes reference to Gulf's recent electric price assumptions. Could you explain what these assumptions are about electric price?

A The major components of the electric price

INDEX OF EXHIBITS

INDEX

STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

APPEARANCES:

GRACE A. JAYE, ESQUIRE, FPSC, 2540 Shumard Oak Boulevard, Suite 370, Tallahassee, Florida 32399-0850.

RICHARD D. MELSON, ESQUIRE, Gulf Power, Hopping, Green, Sams & Smith, 123 South Calhoun Street, Tallahassee, Florida 32301.

JEFFREY STONE, ESQUIRE, Gulf Power, Post Office Box 12950, Pensacola, Florida 32576.

ALSO PRESENT:

MICHAEL HAFF, FPSC Staff.

BILL DICKENS, FPSC Staff.

LEE COLSON, FPSC Staff.

TODD BOHRMAN, FPSC Staff.

ROBERT MOORE, Gulf Power.

MARIA JEFFERS BURKE, Gulf Power.

ELAINE KWARCINSKI, Gulf Power.

* * * *

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of Gulf Power Company)DOCKET NO.990325-EI
to determine need for proposed)
electrical power plant in Bay County)
)

DEPOSITION OF: MICHAEL J. MARLER

TAKEN AT THE INSTANCE OF: FPSC Staff

DATE: Tuesday, May 11, 1999

TIME: Commenced at 9:00 a.m.
Concluded at 9:50 a.m.

PLACE: FPSC
2540 Shumard Oak Boulevard
Room 362
Tallahassee, Florida

REPORTED BY: NANCY S. METZKE, RPR, CCR

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(850)697-8314 / FAX (850)697-8715

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REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of MARIA JEFFERS BURKE; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 14th day of May, 1999.

Nancy S. Metzke

NANCY S. METZKE, RPR, CCR

CERTIFICATE OF DEPONENT

This is to certify that I, MARIA JEFFERS BURKE, have read the foregoing transcription of my testimony, Page 1 through 35, given on May 11, 1999, in Docket Number 990325-EI, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

____

MARIA JEFFERS BURKE

Sworn to and subscribed before me this
_______ day of ______________, 19_____
____
NOTARY PUBLIC
State of ______________________________
My Commission Expires:

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that MARIA JEFFERS BURKE personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 14th day of May, 1999.

Nancy S. Metzke

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

ERRATA SHEET

DOCKET NUMBER 990325-EI
MARIA JEFFERS BURKE
MAY 11, 1999

2, I think.

MS. JAYE: Two is what I have.

MR. MELSON: And that's the Southern IRP material.

MS. JAYE: Right. Okay. Well, that's all the questions I have. Thank you so much.

MR. MELSON: Thank you.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

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have to go back and study it further to give you, you know, any better answer than that, but that's my suspicion.

Q What is that reserve margin target where PROVIEW allowed the generic unit?

A It's 13.5.

Q All right. Going back to the answer to POD 2 on Page 1 of 1 --

MR. MELSON: Interrogatory 2?

MS. JAYE: I'm sorry, yes.

BY MS. JAYE (Continuing):

Q I was wondering if the number of units and the number of megawatts that are used in the base case are a result of the Southern Company IRP?

A In general, it is for the Gulf expansion, for the Gulf analysis. Gulf had a re-powering, I believe, of Plant Crist further out in the expansion plan because that was a decision that I felt like the company had not made for certain what the date was, what the time was, a commitment to those resources. For this analysis we removed that uncertainty from the case, and so our case would differ from the IRP by that amount.

Q Staff had previously requested in request for Production 1 a copy of the IRP for Southern. I was wondering if we could get that again as a late-filed.

MR. MELSON: Sure. It will be Late-filed Number

number of CCs and CTs which will be added on to the Southern System?

A I'm not sure I understand the question.

MS. JAYE: We need to go off the record.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Let's go back on the record.

BY MS. JAYE (Continuing):

Q We notice that in the Late-filed Deposition Exhibit 4 of Mr. Pope the Respondent B for each one of the different years, 7, 10 and 20, shows a delta that changes dramatically between year 4 and year 5 in the far right-hand column. We were wondering if there's a driver for that.

(WITNESS REVIEWED DOCUMENTS).

A It looks to me like that's an artifact of having an exact size unit in there because, if you look at the reserve margin, you can see that in that fifth year the reserve margin climbed as high as 14.2%, .21. You'll notice that that's the highest reserve margin with the exception of the first year that that case has, adding a lot of combined cycles; and using the 500 megawatts exact size of that alternative, PROVIEW case has a minimum reserve margin target. If it's below that minimum reserve margin target by even the slightest number of megawatts, it has to add another 300-megawatt slice size in there. I'd load growth. Southern System gross approximately 700 megawatts a year.

Q Are the numbers under the "Total Megawatts" column proprietary?

A They shouldn't be.

Q Okay.

MR. MELSON: I don't believe so.

MS. JAYE: Okay.

BY MS. JAYE (Continuing):

Q I'd like for you to look at the number for 2020 and compare that to the one in 2021. That's quite a jump. I was wondering if there was a particular reason. And, in general, why they're so much larger than what we see in the earlier stages of the evaluation at the top where you see 2003 and 2004, relatively small numbers.

A In the event that you have -- and I imagine that in the model that there's some unit retirements such as happened in 2021 that requires some additional unit additions. You'll probably notice that in other alternatives that same amount of megawatts is added in each case, so I believe that's something that's just inherent in the base case itself. A resources change is happening, and I would imagine that out that far it's probably some unit retirement assumptions.

Q Does every 300 megawatts correspond to the actual exhibit illustrating cost of each project in total dollars and wanted to know if you were the witness who performed the analysis compromising (sic) this exhibit.

A Yes, I created the numbers for Mr. Pope.

Q Okay. We've got some questions for you about this exhibit then since you're the one who did the numbers.

MR. MELSON: And this is Late-filed Exhibit 4 to Mr. Pope's deposition.

MS. JAYE: Yes.

BY MS. JAYE (Continuing):

Q The first question deals with the very first page of the exhibit where it says "20-year self-build" at the top. There's a column heading "Transmission Losses." Why are transmission losses only evaluated for ten years?

A That's just the way that they do the analysis. There's a lot of uncertainty in that analysis about what kinds of units are added to the system and specifically where they're added, a lot of the definitions. The clarity of that information is really lost after ten years, and transmission planning just performs that analysis to that extent.

Q Looking at the same page here, why do unit additions increase up to six times of the present rate by the year 2021? It's under the "Total Megawatts" heading.

A The most common reason for megawatt additions is in the economic sense, when you have a limited resource like kilowatts or megawatts, it's not an inappropriate analysis to do the net present value across that limited resource.

Q Can total dollars associated with each project be estimated by multiplying the unit size of each project by the dollars per kilowatt values contained in Exhibit MJB-2 of your testimony?

A That is, in fact, how we calculated the 90 million dollars of savings. Where is my exhibit? It didn't make it in my package.

MR. MELSON: Just one minute.

(DOCUMENT TENDERED TO THE WITNESS)

A Yeah. That is exactly how we calculated the 90 million dollars worth of savings that we showed in Interrogatory Number 14. Another approach could be to take the 279 and the 496 and use a 600-megawatt slice size just like we did in the production costing. To be on the conservative side, we used the size that was shown in that schedule and again in Table 8-2 of the need study.

Q Would the true savings then be actually greater than what is shown?

A I believe that the true savings could be higher than the 90 million.

Q Yesterday we asked Witness Pope for a late-filed used instead of the size of the unit, for instance, 574 megawatts?

A Although an analysis can be done with exact size units, it's very difficult to compare a base case, change case scenario because each one of those cases have a different number of megawatts that it's costing out. In the event that you had a 350-megawatt alternative that you were evaluating, my PROVIEW case would have added 300-megawatt slice sizes all around it, and that unit would have suffered a disadvantage because it was that 50-megawatt size. So we've tried to do what we can to make sure the analysis is non-biased by the size of the alternative that's being proposed but rather provides a relative value of the alternatives that we're ranking.

Q Could you explain why it's appropriate to portray a project's cost effectiveness in NPV per kilowatt rather than total dollars?

A One of our challenges, as we try to rank proposals, is to make sure that things like a size bias is not driving the answer. We really prefer to make sure that we are putting on -- adding a unit to the system that has the most value, so we always do the analysis. Most of the fixed costs are provided in dollars per kilowatt month, so we convert those to dollars per kilowatt year and provide a net present value on dollar per kilowatt basis. It really, expansion plan will probably change in that first year or two to mostly CTs. Those are reflected in answer to Interrogatory Number 2, and they're shown -- they're included, the cost for those are included in each one of the alternative spread sheets that you're looking at in Interrogatory Number 1.

Q If you could, please, elaborate on the cause for the cost difference between the base case plan and the project specific plan?

A Depending on the proposal under evaluation at the time, the facilities actually dispatched into all of the resources available to the Southern Electric system, so it may actually displace some units that have a higher dispatch cost. The fuel cost is included in this proposal utility cost for the new unit as well as all of the existing units. Additionally, any variable O&M costs are calculated up, and the expansion plan cost is included in there as well.

Q Was a 600-megawatt block size used to calculate the energy savings column in this table?

A A 600-megawatt block size was used for all of the respondents and self-build alternative for this analysis to make sure that all projects were put and compared to the same exact base case.

Q Just for clarification, why was a 600-block size response to Number 1?

A The answer to your question is yes, but the way that your question was phrased just concerns me a little. PROVIEW creates the expansion plan. We didn't put these expansion plans into PROVIEW. This is a result of the PROVIEW run.

Q Thank you for the clarification.

Do you know where on the Southern Company's system the generic unit additions that comprise the base case will be located?

A To create a base case scenario, we create some generic kind of central locations to the Southern Electric system type of sites. We usually do that really as a, I believe a central Alabama type location rather than a central Georgia.

Q Looking again at the response to Staff Interrogatory Number 1 -- I'm sorry, just a moment.

Okay. Start again. This is, again, the confidential response to Interrogatory 1. There is a column called "Proposal Utility Cost." How does the expansion plan differ from the base case plan?

A When a 600-megawatt slice size of the specific bid alternative is included in the PROVIEW case, we expect that the expansion plan will change through time. For example, if a respondent bid in a combined cycle, the

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Q The tables in Gulf's response to staff Interrogatory Number 1, which is the confidential information, refer to a base case plan. Do you know if this plan consists of generic capacity additions shown in Gulf's response to Staff Interrogatory Number 2?

A I'm assuming by your question that you're talking about the PROVIEW base case that's shown in Column 6, base case utility cost and proposal utility cost.

Q Yes, that's the one.

A And, yes, there are generic unit additions that are included in that cost.

Q Looking now at the Gulf response to staff Interrogatory Number 2, do the numbers in those columns refer to the number of CC and CT units to be added?

A Yeah, these reflect the cumulative expansion plan additions as a result of these proposals being incorporated in our case.

Q What is the size of these units?

A Each one of the CTs and CCs reflected or shown in these columns represent a three hundred megawatt slice size.

Q Is this the plan shown on the base case column, on the response to Interrogatory 2, what was run through PROVIEW to come up with the answer for base case utility costs and for proposal utility costs in the confidential

Losses, Accumulated Present Value." I think it's around Column 15. Did you perform any of the analyses of the cost of transmission losses shown in the column?

A No, just like the grid and connection costs, those were provided directly by Southern Company Services transmission planning.

Q Was it your role just to incorporate those costs then -- those transmission losses rather into the cost effective analysis?

A That's correct.

Q To your knowledge, has the analysis of the cost of transmission losses been provided to staff in any response to request for production of documents?

A I don't know that they have or haven't. I really --

Q Okay. My next question then would be do you know how the analysis of the cost of transmission losses would be calculated or be determined?

A Most likely Witness Pope would be a better person to help you with that.

Q Okay.

MS. JAYE: We need to go off the record for a minute.

(DISCUSSION OFF THE RECORD)

BY MS. JAYE (Continuing):

others -- the numbers for the other respondents, for the proposals that we evaluated were net of the Smith costs.

Q For instance then, turning over one page to the page that is simply labeled Respondent A, the number that appears in the transmission grid and connection column would be the difference between it and Plant Smith?

A Yes, that's correct.

Q Could you explain why the relative ranking was chosen over some absolute numbers or real numbers?

A Certainly. The real goal in evaluation of generation alternatives is to make sure that you're putting the best alternative on the ground, that you're recommending the best alternative, you know, be made available to customers. So your ultimate goal is to create a relative ranking so that you know which alternatives have more value and how much value they have over the other alternatives that are on your plate. So in this particular circumstance it really was not a problem in the event -- because all the numbers were going to roll into a relative ranking table, the numbers would all change by whatever the amount of transmission grid and connection costs for Plant Smith that there were, so it did not change the relative ranking to put the numbers in with Smith as a zero.

Q Staying with the response to staff Interrogatory Number 1, there is a column which is labeled "Transmission

transmission, total cost, accumulative present value, dollars per kilowatt year column?

A Yes, that column would change.

Q Would it change for all of the RFP respondents as well as the self-build?

A It would change all of the RFP respondents by the same amount.

MS. JAYE: We need to take a minute and go off the record.

(DISCUSSION OFF THE RECORD)

BY MS. JAYE (Continuing):

Q In the generation and transmission total cost column, there is a number of 279.15 shown there. What is included in that number?

A That is what we call the net evaluated cost. It takes -- that's what we use for our relative ranking table. It shows how the total costs of Plant Smith rank relative to other alternatives.

Q What costs have been excluded from that number?

A In the column with the heading transmission grid, and connection, accumulated present value, dollar per kilowatt year, the numbers for Plant Smith appear as zeros. That's because the numbers that were provided by transmission were all provided relative to Plant Smith, so the numbers that are really zeros for Plant Smith and the these calculations were done?

A Yes, I do.

Q Okay. Even though you say that you did not actually perform the analyses, was it your role to incorporate these transmission costs into the cost effectiveness analysis contained in Gulf's response to Staff Interrogatory 1?

A Yes.

Q Okay. Looking again at the column in question, does the column indicate the cost of transmission additions and upgrades associated with Smith Unit 3 in each RFP project?

A The costs are the relative costs and not the absolute dollar values. The numbers that were provided by transmission were netted basically by the cost of the Smith Unit 3.

Q Do you believe that it is appropriate to show transmission cost impact of Smith Unit 3 as zero if, in fact, there are costs involved?

A I think in the relative ranking it doesn't make a difference whether you include a capital cost in there for Smith and include that same capital cost for every other project. The relative ranking should be the same.

Q If the true costs were contained in this table, would that then change the answer on generation three columns, the very first one that shows -- These numbers (indicates).

A Right.

Q Okay.

MR. MELSON: None of the column headings are proprietary, so if it makes it easier just to read the column headings, that's great.

MS. JAYE: Okay. Great then. And that would be the transmission grid and connection accumulated present value, dollars per kilowatt year.

BY MS. JAYE (Continuing):

Q Did you perform any analyses on the transmission costs shown in this column?

A The transmission numbers were provided directly by Southern Company Services transmission.

Q Do you know if the costs in the column were taken from Gulf's response to the staff Request for Production Number 2?

A In -- well --

MS. JAYE: Okay. We need to go off the record for a minute.

(DISCUSSION OFF THE RECORD).

MS. JAYE: Back on the record.

BY MS. JAYE (Continuing):

Q Ms. Burke, do you have an understanding of how

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need to pay that fixed fuel transportation reservation up front, but you do pay for it when you use it; and, therefore, you have a higher fuel cost delivered to your site for CT than for CC.

Q I'd also like to compare information on Respondent B, CC, 20-year pricing sheet, to that for Respondent C. Again, we'll be looking at the far right-hand set of columns and the center of those columns.

A There are two Respondent C sheets. Are you looking at the one with the levelized energy price or the one that's just marked Respondent C?

Q The one just marked Respondent C.

A The difference in these two fuel pricing really relate to how the bidders bid in the fuel price that we would actually pay for the fuel at their facility. Respondent B bid a City Gate index, and Respondent C bid a Henry Hub plus 4%, so that the two different pricings are associated with the respondents themselves and what they proposed that the company would pay for fuel.

Q All right. Ms. Burke, the next set of questions are going to deal with transmission. Those are going to deal mainly with the transmission grid and connection accumulated present value costs which are to be found in confidential response to Staff Interrogatory 1. Looking at the table, it will be in the main table, the middle set of commodity price of gas. In the self-build alternative, this particular supplier that responded to the fuel RFP provided a, almost a contract type of price for the commodity that was below what the Henry Hub type price would be. That's why those numbers are lower.

Q All right. We're now going to look at the confidential information that was identified in Gulf's response to Staff's Interrogatory 1. We'll be comparing fuel prices that appear on two different pages. One is Respondent B, CC, 20-year pricing. The other is Respondent B, CT proposal, 20-year pricing. On the far right hand there are three columns in a separate box. I was wondering if you could compare the numbers in the center of those three columns between the first sheet mentioned and the second.

A Surely. The numbers for the CT represent a fuel price with additional pricing volatility in there and additional transportation components for that delivered fuel price cost. If you look back at the combined cycle alternatives, you'll see that we have included earlier in the table, Column 2 or 3, a fixed fuel transportation cost; so you paid a lot of that variable transportation component up front in your fixed fuel reservation charge. Because you're going to utilize a CT much differently than you would utilize a combined cycle, there's really not much

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for any actual information, but let's go off the record.

(BRIEF RECESS)

BY MS. JAYE (Continuing):

Q Ms. Burke, while we were off the record, we identified some confidential documents as TB-1 and TB-2, and I wanted to ask you a series of questions about those in general terms if you can respond to those. There's some concern that the variable transportation component between what is shown on sheet TB-1 and what is shown on sheet TB-2 are extremely different, and I was wondering if you could explain the divergence. One looks to be almost twice as much as the other.

A The costs that are shown on TB-1 are for the Smith unit. Those costs were supplied by a particular respondent to the gas RFP that was published, so the variable transportation costs that are shown there relate directly to that respondent's bid.

Q All right. There are columns included on both TB-1 and TB-2 which fall under the label FGT, and I believe it is in the first column under that label. There are some numbers that from one sheet to the other are quite different, and I was wondering if you could explain the dollar difference between those numbers.

A Certainly. Those columns should represent the proposed for outside vendors. We only used this RFP to vary the different fuel alternatives for the self-build alternative.

BY MS. JAYE (Continuing):

Q Turning now to the response to staff's Interrogatory Number 17. I was hoping you could help me clarify my understanding of this response. Is this response indicating Gulf Power assumed that Southern Company Services would supply the natural gas for the Holmes County combined cycle unit? I believe we're actually referencing the confidential information that was provided.

A Oh, okay.

Q It's the page with the title "Southern Electric System 1998 Projections of Generic Nominal Natural Gas Prices."

A They all say that.

Q That's helpful.

A Are you talking about the combustion turbine project or the combined cycle projection?

Q Combined cycle.

MR. STONE: If we're going to talk about the confidential, can we just go off the record first and make sure we get things clear?

MS. JAYE: Well, I'm certainly not going to ask

QUESTION)

MR. MELSON: I'm not sure I understand the question, unfortunately.

MS. JAYE: The question is seeking to understand if information that was obtained in the separate RFP for the natural gas service, and evidently firm supply and the commodity itself bundled, if that information was applied across the board to all of the nine finals.

MR. MELSON: In other words, was each respondent modeled as though he had the benefit of that particular firm gas transportation number?

MS. JAYE: Yes.

THE WITNESS: Oh.

MS. JAYE: Yes.

THE WITNESS: Oh, that's a different question. Okay. Because it was a packaged deal, there is really no way to apply those gas prices to other sites that were involved in the solicitation. We applied the numbers that were provided from fuel. We applied them uniformly to the self-build alternative the same way we would have applied those numbers for a bid in the event that a respondent outside the company had made that for their electricity generation, but we maintained the integrity of the bids the way they were outlined in the RFP, in Attachment C of the RFP; and they understood that going to some of these gas suppliers there was a possibility that some of those gas suppliers could package the commodity with some of the transportation and maybe reduce the cost that we thought was there.

Q In what form is information obtained in response to the September 1998 RFP?

A Respondents supplied written responses to the RFP.

Q Okay. How were those used in evaluating the self-build alternative?

A Southern Company Services' fuel department provided the initial screening of the proposals, and they sent to us, the evaluation team, four respondents and a self-build cost; so we evaluated five self-build alternatives.

Q Was the additional information obtained in the separate RFP for the firm natural gas service applied consistently among all nine proposals that were evaluated for the final stages?

A Yes.

Q Okay.

MR. MELSON: I missed that. Could I get that question read back?

(WHEREUPON, THE COURT REPORTER REREAD THE associated with that: What's the incremental cost of debt? What's the incremental cost of capital? And it will create the declining revenue requirement stream for that.

MR. MELSON: Can we go off the record for a minute?

MS. JAYE: Certainly.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Okay. Go back on the record.

BY MS. JAYE (Continuing):

Q Ms. Burke, how many of the RFPs that were received in response were for 20 years?

A Besides the self-build, we had three proposals that were 20-year proposals.

Q Okay. The next question is going to come from your direct testimony, Page 11, Lines 1 through 10. It's the sentence beginning, "In September, 1998."

MR. MELSON: What's the page number?

THE WITNESS: Eleven.

MS. JAYE: Page 11.

BY MS. JAYE (Continuing):

Q In the September 1998 RFP that's referenced on Lines 1 and 2 here, was Gulf attempting to purchase natural gas commodity or natural gas transportation?

A Actually both. They were working hard to reduce some of the gas lateral costs to the facility that were

A I have, I guess, made an assumption that putting this unit in rate base would inherently create a 30-year declining revenue requirement type of cash flow of revenue to the company for the unit. What we did instead for this analysis was to compress that recovery time frame across 20 years so that all of the costs had to be recovered in a 20-year time cycle instead of in a 30-year time cycle. That really produced higher declining revenue requirements because you had to fully recover the unit across 20 years instead of recovering the unit across 30 years or longer, depending on what Florida's regulations require.

Q Did this result in interest savings?

A Interest savings. Like the rate of interest?

Q Uh-huh. Between the 20- and 30-year time frame.

A No, we used the same interest rate that we used for generic units.

Q So the interest that would have been accumulated between year 21 and year 30 goes away, the cost of money over the last ten years of the 30-year cycle versus the 20-year cycle?

A Goes away. I guess I hadn't -- I'm having trouble understanding what you're saying. We took the 187 million for the 540-megawatt size facility and basically put it in -- we have a little spread sheet model called Rev Req that finance has written for us to take the cost

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increment.

Q Okay.

MS. JAYE: I'm going to need a moment here. Go off the record.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Okay. Back on the record.

BY MS. JAYE (Continuing):

Q I've got some questions about statements appearing on Page 65 of the need study. For this particular need study, did Gulf and, you know, by extension Southern Company, choose to make cost comparisons of all the RFP respondents and of the self-build option on a 20-year period of cost basis?

A It is very important in the analysis to make sure that you're comparing alternatives across an equal time period, and the best way to do that is to pick one time frame. Gulf selected a 20-year analysis period, and that's what we used.

Q Okay. Could you explain what that next sentence means where it says, "Theoretically the cost of any new generating facility constructed by Gulf would be recovered from its customers using declining revenue requirements over 30-year or longer time frame?" Is that what you would normally do, and how does this differ as far as the interest savings to customers, et cetera?

THE WITNESS: Well, hold on because I just told you the answer for Respondent C. I apologize. I got confused. I thought we were talking about Respondent C.

(WITNESS REVIEWED DOCUMENTS)

THE WITNESS: Respondent B was locating a facility in Holmes County, Florida that is within Gulf's service territory, and the cost for the improvements was 104.6 million.

BY MS. JAYE (Continuing):

Q Okay. Do you know how many circuit miles that location would be from Gulf's proposed facilities in Bay County?

A I do not know.

Q Okay. Or the cost per circuit mile?

A I do not know.

Q Okay. Is it true that Gulf scaled each RFP respondent's proposal to a 600-megawatt generic unit to do a production costing analysis?

A That's true.

Q Was this cost spread over 20 years?

A There's no need to spread production costs across different years. The production cost model annualizes the total cost, and so I had a total dollars cost for every year, simply divided that cost by the 600-megawatt

Q Okay. Do you know how many circuit miles this location -- the location for the Holmes County respondents would be from Gulf's proposed facilities in Bay County?

A No, I don't know that.

Q Okay. Do you know what the transmission cost was that Gulf applied to Respondent B's RFP?

(WITNESS REVIEWED DOCUMENTS)

Q I believe that some of this response, and you may have found it, but, you know, I apologize for not being able to direct you exactly where in the discovery these questions are coming from. This is actually on the response to Interrogatory 4. I believe that this had been summarized there, and I'm just trying to get a handle on the information.

A The confusion could be really because I knew that the Southern Company, that the price -- that the price that Respondent C offered was inclusive of the transmission cost to the interconnection point, Southern Company's interconnection point. After that point, our transmission planners assess a total cost of 104 million dollars to this project -- 112.6, I apologize.

MR. STONE: The question was about Respondent B, was it not?

MS. JAYE: Yes, Respondent B.

MR. MELSON: I'm sorry.

MR. MELSON: All right. Yeah.

MS. JAYE: We can go off the record.

(DISCUSSION OFF THE RECORD)

MR. MELSON: Yes, go back and identify it as a late-filed exhibit.

THE WITNESS: Yes, I don't believe we'll have a problem complying with the late-filed exhibit request.

MS. JAYE: All right. This will be Late-filed Exhibit Number 1. We'll call this the correspondence between Gulf and the RFP respondents.

BY MS. JAYE (Continuing):

Q Do you know if the Respondent C would use the same power plant technology as Gulf would use in a self-build option?

(WITNESS REVIEWED DOCUMENTS)

A This particular respondent outlined information about their 750-megawatt facility. They did mention two manufacturers' names, but not necessarily -- one of them is one that Southern Company deals with a lot; one of them is not. So in their design, I would expect that their design would differ somewhat from Southern Company's design of a self-build unit.

Q Are you familiar with the results of the fatal flaw study which was conducted by Respondent C?

A No, I'm not.

not confidential, but I don't know. So I want her to think about that before she answers the question.

MS. JAYE: Okay.

(WITNESS REVIEWED DOCUMENT)

THE WITNESS: This particular respondent estimated that across the six-year maintenance cycle that the availability would exceed 9½%, but the annual forced outage rate was estimated, or would have been guaranteed at two and a half percent.

BY MS. JAYE (Continuing):

Q Okay. Do you know what the interconnections were for this particular respondent with the Florida Electrical Grid?

A I don't know. They actually provided a good bit of information that they had a consultant do with the interconnections. Because they were outside of the Southern Company service territory, they -- the interconnection cost was not really a part of our scope.

Q Okay. I believe we had some information provided pursuant to the staff's Request for Production Number 3 which has subsequently been returned to the company, some confidential information that showed correspondence between Gulf and the RFP respondents, and I was wondering if we could get that as a late-filed deposition exhibit, get that filed again.

after I married and worked as a research engineer for a while and joined system planning not too long after that.

Q I'm going to jump right in here and start asking you some questions about the different respondents. Pretty much of this information can be found in the need study around Page 64 or 65, in this area. We're going to be all over the lot for a while. I'll go ahead and give you the heads up.

A Okay.

Q I've got a question about Respondent C's RFP. Was that to provide 532 megawatts of dispatchable capacity for a proposed 750-megawatt project to be located in Hardee County?

A That's on Page 64.

Q It's all within this area. I believe the actual numbers are over on Page 67 for that in the Table 8-1.

A Yeah, Respondent C provided 532 megawatts or proposed 532 megawatts of a larger facility in Hardee County, Florida.

Q Okay. Do you know what the availability factor for this plant would be?

A I can look that up. It's not in this text.

Q Okay.

MR. MELSON: Now let me ask, before she answers the question -- I assume the availability factor is

Whereupon,

MARIA JEFFERS BURKE

was called as a witness by the Plaintiff and, after being first duly sworn, was examined and testified as follows:

EXAMINATION

BY MS. JAYE:

Q Nancy, go ahead and insert the usual stipulations. Thank you.

Good morning, Ms. Burke.

A Good morning.

Q I'm just going to ask you a little bit about your background with the Southern Company. How long have you been with Southern Company?

A Almost 13 years.

Q And during those 13 years, what positions have you held?

A A variety of positions. I began the company as a research engineer at a research plant in Wilsonville, Alabama, and I had a variety of positions there. The company that actually operated that facility was Southern Electric International at the time. I went to Atlanta and was the environmental engineer for that development office for new projects, just like the folks that are bidding into this solicitation. From there I went back to Birmingham

INDEX OF EXHIBITS

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STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

APPEARANCES:

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ALSO PRESENT:

MICHAEL HAFF, FPSC Staff.

TODD BOHRMAN, FPSC Staff.

ROBERT MOORE, Gulf Power.

ELAINE KWARCINSKI, Gulf Power.

* * * *

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of Gulf Power Company to determine need for proposed electrical power plant in Bay County) DOCKET NO. 990325-EI

DEPOSITION OF: MARIA JEFFERS BURKE

TAKEN AT THE INSTANCE OF: FPSC Staff

DATE: Tuesday, May 11, 1999

TIME: Commenced at 10:00 a.m.
Concluded at 2:00 p.m.

PLACE: FPSC
2540 Shumard Oak Boulevard
Room 362
Tallahassee, Florida

REPORTED BY: NANCY S. METZKE, RPR, CCR

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REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of WILLIAM F. POPE; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 10th day of May, 1999.

Nancy S. Metzke

NANCY S. METZKE, RPR, CCR

CERTIFICATE OF DEPONENT

This is to certify that I, WILLIAM F. POPE, have read the foregoing transcription of my testimony, Page 1 through 69, given on May 10, 1999, in Docket Number 990325-EI, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

____

WILLIAM F. POPE

Sworn to and subscribed before me this
_______ day of ______________, 19_____

____
NOTARY PUBLIC
State of ______________________
My Commission Expires:

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that WILLIAM F. POPE personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 10th day of May, 1999.

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE, INC

ERRATA SHEET

DOCKET NUMBER 990325-EI
WILLIAM F. POPE
MAY 10, 1999

(DISCUSSION OFF THE RECORD)

MS. JAYE: Okay. Back on the record.

MR. MELSON: Apparently the spread sheets at this point are almost final.

MS. JAYE: Okay.

MR. MELSON: What we would like to do is go ahead and identify them if we could as a late-filed exhibit for Mr. Pope. We'll try to get those filed this afternoon, if we can, with a notice of intent for confidentiality. And then to the extent you've got questions about them, Ms. Burke ought to be able to answer those questions tomorrow.

MS. JAYE: Very good. That sounds great.

Okay. That's all the questions we have then. We'll reserve the rest for Ms. Burke.

MR. MELSON: Gail.

MS. KAMARAS: I've got no questions.

MR. MELSON: No redirect.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

when those type of more efficient and lower cost units are put into the mix, they do displace higher cost units to the benefit of all and Gulf Power Company.

Q Okay. The next set of questions deal with cost effectiveness. Staff has prepared a spread sheet, and we apologize for the small type, but we have indicated several columns, and we would appreciate it if you could fill it in for us and return it as a Late-filed Deposition Exhibit Number 4. And we'll title that revenue requirements spread sheet. This, I believe, staff has provided to your counsel.

MR. MELSON: Right, and my recollection is that when we had the informal meeting and discussed this there were some changes, I think, in the reserve margin presentation that we agreed to. I assume you want what we have talked about during that meeting as opposed to the columns that are shown here.

MS. JAYE: Yes.

MR. MELSON: Actually, this is probably a document that will be produced by Ms. Burke rather than by Mr. Pope. I don't mind identifying it. However you want to handle that mechanically, I don't care, but she would ultimately be the one to speak to the numbers.

Go off the record.

A Yes. The benefit as determined in those columns, and there are benefits, basically demonstrates how Gulf, being a part of the Southern Electric system, and any alternative that it may consider or evaluate that would be a lower cost and displace higher cost generation has direct benefits from a marginal energy cost on an hour-by-hour basis directly to, not only Southern Company, but Gulf Power Company as part of the Southern dispatch pool.

Let me clarify that a little further. What I'm saying is that any alternative that we evaluate, according -- and stacked up against the base case, that displaces a higher cost unit has direct benefits on a dollar per megawatt basis directly to that option that is lower cost. That's what is tried or we attempted to capture and did capture in that analysis in the PROVIEW cases.

Q So in your opinion, the development of the proposed Smith Unit 3 would replace older dirtier, less efficient units and, thereby, be a net benefit to Southern and to Gulf?

A Well, you only -- Let me just respond to the fact that the higher cost units were displaced and would be displaced by the Smith CC or Smith Unit 3; and, of course, some of the other alternatives did have some lower energy costs as well because they were like type of units. But

Number 3 would still be the same, no matter which one was used.

Q Okay.

MS. JAYE: We need to go off the record a minute.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Go back on the record.

BY MS. JAYE (Continuing):

Q Looking, again, at the Gulf response to staff Interrogatory Number 1, there were two columns here called "Base Case Utility Cost" and "Proposal Utility Cost." These appear to be derived from Southern Company numbers. Is this the case?

A It's a Southern -- total Southern Company is modeled in that PROVIEW model that we ran these cases on, that's correct.

Q Okay. Does the IIC factor into these two columns?

A The IIC, intercompany interchange contract or IIC, is not a factor and not any part of those calculations whatsoever.

Q Could you explain how the addition of a unit which would be cost effective to Southern could be cost effective to Gulf as well? In addressing the question, would you speak to the nature of the unit being a CC and the sort of fuel that will be used, et cetera?

requirements, et cetera, that were provided.

A Certainly. When looking at any of these alternatives, the Smith Unit 3 option and any response or offer, the company looks at the total cost impacts to the company based on those offers, the transmission associated and energy and O&M costs. You take all of those factors, all of those numbers and you add them up and present value them to 2002 dollars, which gives you a -- in our case -- a dollar per kilowatt total evaluated cost to Gulf Power Company for those projects.

Although a Southern financial assumption was used to come up with the cost effectiveness dollars, it would matter not for the ranking purposes whether that was a 12% return on equity or a 14% return on equity as far as the ranking goes. The dollar amount, the raw dollar amounts may change. No, they will change. If, for instance, the assumed return on equity were 12%, the numbers, all the numbers would go up slightly, but Gulf's differential between its next best alternative would increase because it would have a lower cost risk capital and a higher dis -- or a lower discount rate. That's why all numbers would go up, because your cumulative present values would all go up; but Gulf's cost to construct transmission and generation would go down more, so the differential in the two would get greater. The cost effectiveness is still the same. Smith between the column "Grid and Connection Accumulative Present Value Dollars per Kilowatt Year," and how that would impact the general and transmission total cost column at the end of that row?

A If it were calculated and filled in --

Q If it had its numbers.

A It would increase those dollars per kw figures individually by year and, of course, the total. Likewise, if the others were likewise included, they would increase their numbers too. The ranking would still stay the same.

Q Okay. I'm going to move on and ask some questions on the cost effectiveness. As a layman, are you generally familiar with the provision in Section 403.519 of Florida Statutes that requires a proposed unit to be the most cost effective alternative available?

A Yes.

Q Okay. Do you know if Gulf is justifying the proposed Smith Unit Number 3 as the most cost effective alternative available to Gulf or to Southern Company?

A To Gulf.

Q Okay. Could you explain how that is determined when the analyses that were done were based upon Southern Company?

A You talking about financial assumptions?

Q Yes. We're talking about the revenue

A And there are zeros there. And your question is?

Q If the information that you just explained would go under that column.

A Correct, that's where you'll see it on all of the spread sheets that are associated with the RFP. The reason this one is zero is because we take -- we assume Smith Unit 3 to be the base, so we extract its annual dollar per kilowatt year cost from the others and basically say Smith is the base so we're just going to say it's zero. The others have numbers in there, but that's the difference between what Smith's improvements would cost and their improvements would cost.

Q Okay. Do you believe that it is appropriate to show the transmission cost impact of Smith Unit 3 as zero if, in fact, there are costs?

A I think it's just a choice of representation. It could just as appropriately be shown, as opposed to being zeros and taken the difference for the others, it could just as appropriately be shown as its cost alone and then the total cost of the others. The same result is going to occur.

Q Mr. Pope, if you could reference the response to staff's Interrogatory Number 1 again, the same page we were looking at before. Could you speak to the relationship of the cost effectiveness. But you present value those, and you present value revenue requirements.

There are some O&M implications from transmission. Those were added in on an annual basis and present valued in like manner. What that gives you for all the transmission improvements is a present worth revenue requirements of their capital and O&M, which are added into the cost effectiveness from a total cost basis.

Q There was some information provided in response to staff's first set of interrogatories, Number 1. There's a column heading here, and I would just for like for you to tell me if what you've discussed belongs under this heading. It's called "Transmission Grid and Connection Accumulative Present Value." Those are dollars per kilowatt per year. Is that --

A That's in response to Interrogatory 1?

Q One.

A And which one is that so that I'm making sure that I'm on the same page as you are.

Q A page that looks like that.

A Yeah, this is the spread sheet for Smith, the Smith 3 in the RFP process. And you're talking about the column that says "Transmission Grid and Connection Accumulative Present Value in Dollars Per Kilowatt Year."

Q Yes.

transmission additions and upgrades were incorporated into the cost effectiveness analysis for each self-build option and RFP project?

A Excuse me. Could you please repeat that?

Q Certainly. What staff is looking for in this question is an understanding of how the costs for transmission additions and upgrades were actually incorporated into the cost effectiveness analysis for each self-build option and RFP project. What we would like is a discussion of the conversion of capital cost to revenue requirements, et cetera.

A Okay, I got you now. I just wanted to make sure I got the full scope of it.

Q Okay.

A The transmission improvements, and all cases have some transmission improvement, the capital cost of the transmission improvements are used to calculate a present worth revenue requirement, standard declining revenue requirement stream. So you add those up for each case, all the revenue requirement streams for all the transmission improvements and you present value them to 2002 in the case of the RFP.

In the case of the self-builds, we present value that same number to or like number to 1998 dollars. That's one difference between the two. But it's still reflective correct information?

A The omission was from the standpoint that it said -- the petition said that there are no transmission facilities directly associated with this unit, and I believe that need petition will be amended to reflect that there are, and those lines will be listed. I want to point out though, however, the costs of those improvements in the RFP analysis evaluation were included, so the costs, as far as cost effectiveness goes, were included; but it just was omitted from the petition itself as an oversight.

Q Okay. In Gulf's response to staff's Interrogatory Number 4, it appears that the self-build option, which is Case Number 3, and the RFP Case Number 4, both pertain to a Smith combined cycle unit. Could you explain why the costs are so different for these two options when they appear to pertain to the same plant?

A Okay. For one thing, in the self-build option, self-constructed case of the initial evaluation, we were looking at smaller unit and, therefore, there were less impacts in the Panama City area from the local transmission. When you raised the capacity of the unit addition to nearly twice what was initially evaluated, you added some other incremental improvements in the Panama City area.

Q Could you briefly explain how the cost of various alternative solutions to those, and then you generate costs associated with those and select the most cost effective. But, yes, they did.

Q In determining the cost for each new line and upgrade for the self-build option, RFP options, were the costs determined using some standard method or by a special method?

A Each improvement has to be looked at individually because some can be a conversion of an existing smaller line, say on existing right of way. Well, you need to treat that differently than if you bought new right of way with a new construction, so I'd have to say they're all special. There's no, there's no -- you know, five miles of line is a million dollars. No, it's -- there are some common assumptions for certain areas having certain -- or certain size lines having certain dollars per mile to install. Substations, depending on what they have in them are a certain cost, but you have to still treat it individually as to what kind of addition it's going to be.

Q Okay. On the last page of Gulf's response to staff's Interrogatory Number 4, there's a discussion that some transmission costs were inadvertently omitted from the need petition.

A Correct.

Q Will Gulf amend the need petition with the units, et cetera, so on and so forth.

Q What percentage in general of the reserve would be allocated to tie assistance?

A Probably in the one and a half percent range.

Q In order to allow staff to better evaluate and understand the differences between EAF and EFOR, staff would request that you provide a late-filed exhibit -- th: one, I believe, will be Number 3 -- which will provide Southern Company's historic and forecasted system EAF for each year from 1994 to 2004, and we'll give this a title system wide EAF, 1994 to 2004.

A Okay.

Q All right. Thank you.

MS. JAYE: I think we need to go off the record and take about a five-minute break and let staff regroup here.

(BRIEF RECESS)

BY MS. JAYE (Continuing):

Q These questions pertain to Gulf's response to staff's Interrogatory Number 4. The response to Interrogatory Number 4 contains the cost for each new line and upgrade for each self-build and RFP option. Did these costs come from the transmission study?

A Yes, the lines were identified in this study, okay? And then as I mentioned earlier, you look at the forecast error, forced outages, and abnormal weather.

Q Could you elaborate a little on this ties?

A Your ties or tie lines or interconnections are the power lines that you have with neighboring utilities. The Southern Electric system is interconnected with the Entergy system, the TVA system, the Duke system, the Virginia/Carolina systems, and Peninsular Florida. So we have five basic sources that at any point in time, if we were to lose a large generating unit, that powers would -- power flows would change. Because of the generation in those areas and their generators having a certain amount of inertia, they will pick up, power will flow where it needs to flow until generation, additional generation can be either brought on the Gulf system or the Southern system or we can make arrangements with others to pick up their generation to help us through depending on the condition.

That's what we call tie systems. That's where our interconnections will help us from a reliability standpoint. On a planning basis, we can look at it both short term and near term. We also look at our generators as having certain types of reliability responses. Some of our generators are what they call quick-start capability, can be on line in ten minutes. That meets the NERC criteria as a reserve, a spending reserve. So tie systems is something we look at to analyze the effects of losses of cover that from a reserve standpoint.

There are load forecast errors. Your load forecasts for tomorrow may be very accurate; but three years, five years down the road when you'd would have to make commitments for today to build, they may not be as accurate. Economic conditions could change, change in the pattern of use. So we try to account for load forecast errors with reserves.

There's also abnormal weather conditions. Most forecasts are produced on a weather normal basis, which for the summertime -- which Gulf is a summer peaker -- we assume a 95-degree ambient temperature as a weather normal or 94-degree weather normal temperature for a summer peak day. Well, if it's 102 for five days in a row, your demand is going to be higher. That's an abnormal weather condition.

Ways that we can meet those reserves are with additional generation or outside sources. Operationally -- That's on a planning basis. Operationally, on a day-to-day basis, we have a certain amount of our interfaces that we depend on, depending on what they're being used -- how they're being used on a day-to-day basis. So there is some reliance on outside sources, or what we call tie systems, as well as generation resources above that of our normally expected demand to take care of load way of looking at things is not an indicator of things that you unexpectedly have happen. A unit could be a hundred percent available and have a 100% equivalent availability factor in one year, but never be called on to generate, never crank itself up; therefore, you don't know if it could have run if called upon or not.

So that's an indicator where it would say that you don't need to do anything for this unit; however, the next day after the new year that this equivalent availability factor was a hundred percent, they call it up to run, and it can't run. But was it really available? Well, at that point it's a forced outage, and that's the thing, is you are trying to cover for the unexpected things which are measured by equivalent forced outage rate and not equivalent availability factor. Like I said, from a reliability standpoint, it is not what we consider to be the thing that we want to protect against.

Q What are some other things which Southern Company would look to in order to analyze its reliability factor besides the EFOR and EAF?

A In all instances reliability is to cover things you didn't plan on. Your equivalent forced outage rate is something you'd like to have your units run all the time, but there is going to be some likelihood they're going forced out. That means that probablistically you need to for a moment?

A Okay.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Okay. We're back on the record now.

BY MS. JAYE (Continuing):

Q Turning now to the response to Staff Interrogatory Number 28, Gulf has provided historic equivalent forced outage rates on the Southern Company System. We understand that EFOR is a better measure of the frequency and duration of outages, but we would like to understand why it is better for this purpose than the equivalent availability factor or EAF?

A The equivalent forced outage rate is, it tracks and calculates your forced outages. Forced outages are surprises. They are unplanned, unexpected. They are a demonstration of what the unit can be expected to be off line for unexpected reasons. The Southern Electric system, I guess along with some other utilities, look at the equivalent forced outage rate as a better indicator of a need to cover reliability. You need to cover for this unexpected outage of a unit, therefore, use EFOR.

The equivalent availability factor or EAF, only demonstrates what a unit is available or, you know, is demonstrated or shown to be available. Not demonstrated, but they can report they're available. Availability in my comes primarily because when they're adding capacity resources, it's large units to meet their needs, which are large needs. And Gulf and the size it is with a growth of about 30 to 40 megawatts a year, easily a short excess from them, which is a big amount of capacity, takes care of Gulf's little bitty needs; and typically the larger -- like I said, the larger companies are the ones with the excesses.

Now how are reserves allocated? Roughly in the planning arena, under a 13.5% reserve margin, all individual operating companies, because of diversity, should have, and carry 12.6% reserves. If, for instance, Georgia Power Company in one year had 15% reserves, that leaves a large chunk of megawatt to be reallocated to other companies that are short of their 12.6. Basically those with the lower reserve margin, individual reserve margins get a varied proportion of those excess reserves.

Q Does this mean that Gulf plans its system additions to meet a 12.6% individual utility reserve margin?

A That's correct. That's what we consider to be our reasonable share of Southern's reserves based on 13 and a half percent.

Q The next question goes to the response to Staff's Interrogatory Number 28. We also need to go off the record it Gulf's turn to add capacity because Gulf is a primary driver for Southern's 2002 capacity need?

A No, Gulf is not necessarily the sole driver for Southern's needs, but a number of companies are now needing to add capacity. Gulf has not added capacity in a number of years because it's enjoyed the benefits of both relying on the Southern Electric system and its short-term excesses of capacity plus purchases, cost-effective purchases; and now cost-effective purchases, because recent market tests appear not to be available, we have found them out there. We have gone out and asked people to provide us quotes and information which have not been as cost effective as the generation, but it's because Gulf and other companies in Southern Electric system are all having to add capacity. And Gulf has no other recourse than to go negative with reserves, but it can't rely on the Southern Electric system without them adding or us adding, which still costs us; and this is the most cost effective alternative we found.

Q Could you explain how the Southern Company members share their system reserves, i.e., how the reserves are allocated, which utilities are primary suppliers of reserves and that sort of thing?

A Primarily your larger companies, which are Georgia Power Company and Alabama Power Company, typically have, more often than others, excess reserves; and that

13.5%?

A Excuse me. Ask that again.

Q How much capacity will Gulf Power need on its system in the year 2002 in order to meet its reliability criteria?

A In 2002, Gulf itself is 427 megawatts short of meeting its capacity and reserve obligations according to the 13.5% Southern target reserve margin.

Q How much capacity would Gulf need in the year 2002 if its reserve margin criteria were 15%?

A Can I take a minute to calculate that?

Q Certainly.

MR. MELSON: Before he finishes his calculation, how much for Gulf to meet a stand-alone 15% reserve, or how much for Gulf to meet its share of a Southern 15% reserve?

MS. JAYE: Stand-alone 15%.

MR. MELSON: Okay.

THE WITNESS: 482 megawatts.

BY MS. JAYE (Continuing):

Q How much new capacity does the Southern Company system typically need to add each year?

A At this time it's currently about 600 megawatts a year.

Q Among the Southern Company member utilities, is

Q Looking again at this graph on page 47 that we've been discussing, it appears that it remains flat for quite sometime around the 13 or 14% level. What does that mean in terms of cost? Would it matter then if you picked 13, 14, or 15%?

A You're right. The curve, as it comes down to the 13 and a half to 14% range, it gets flat and looks to be fairly flat on up to around 15 and a half, 16%. And the reason it comes down steeper to the left to that point is because generation is very sensitive to the loss of energy to the left, but since there's a low cost of generation out beyond that point, you don't gain much from your reliability as you get beyond 13 and a half, 14, 15% as far as reduction in EUE cost for the same -- for an increment of generation. So, yeah, it says reliability wise, 13 to 15%, the reason you pick 13 and a half percent is because that costs you less money. It's less investment for relatively the same reliability cost. In other words, you still -- you wouldn't go build the extra dollar if it doesn't buy you anything.

Q Does Gulf Power Company have its own planning criteria?

A Not a stand-alone criteria, no.

Q Okay. How much capacity will Gulf Power need on its system in 2002 to meet the reliability criteria of curve. It's what we call the bathtub curve. It looks kind of like a bathtub. Where that total curve reaches zero or a zero slope or reaches its minimum is the area you want to have -- that's your optimum reserve point.

Q Mr. Pope, if you look at the center of the graph where it is calculating reserve margin, there appear to be two 14%. I was wondering if you could explain that. Is it 14 and perhaps it should have been 14.5? I don't quite understand. It looks to be at the minimum point on the curve?

A I can say it's a consistent error because it's on Page 51 as well. I believe there may be another curve somewhere here that clarifies it, but -- Good point.

Q Also, I didn't see on here a point on the graph that corresponds to a 13.5% reserve margin, and I was wondering if perhaps one of those was supposed to be the 13.5 instead of 14.

A Possibly. I'm just going to have to clarify that to find out. If I don't find it here in a minute, we can find that out.

MS. JAYE: We can go off the record for a second if that would be all right with everyone.

(DISCUSSION OFF THE RECORD)

MS. JAYE: All right. Back on the record.

BY MS. JAYE (Continuing):

outages. It means that you can build a lot of generation without worrying about it, but the cost of what you avoid goes down. And that -- those counterbalances went to the left rather than in the center or to the right.

Q Mr. Pope, I want to be sure I understand this. There are two curves involved in setting the reserve margin, and I was wondering if you could explain to me what they represent. Is it EUE and cost of generation? You were discussing if one goes up, the other one goes down, and --

A Yeah. Let's refer to a page in the POD response, the July 1997 document, Page 47. This is a graph of total cost as it relates to reserve margin. The dark colored lines -- Starting at the left around 9%, you'll see that's a solid dark line. That represents the amount of expected unserved energy times the cost of that unserved energy at $4.34 a kilowatt hour, okay? That's the dark line.

Moving to the right, you'll see a straight line that's lighter colored on that bar that starts to inch up. That's the cost of adding reliability generation to avoid lost energy. Now you'll see your dark line not only in total, as the total sum of those two comes down; but as an increment per reserve margin it gets smaller and smaller. But it's a summation of both the cost of unserved energy and the generation to avoid it, which describes the total

A Let's start with the initial one, 1991, that used the cost of reliability generation as a factor to reduce loss of load or loss of energy. There is a loss of energy and a cost of that loss of energy, what we call expected unserved energy. The '91 case identified the cost of expected unserved energy, or EUE, to be priced at $7.31 a kilowatt hour. So that establishes a cost that you would basically assign for the power that a customer loses. Then you would build units at a cost of that construction to avoid that.

That's what the 1991 study started with. It changed from '91 to '94. It's primarily the cost of that unserved energy going from 7.31 to I believe $8.34 per kilowatt hour. The cost of generation actually goes down. The cost of incremental generation to avoid goes down. We chose in that time to not make a change because it looked like the curve stayed in the same place.

The change from '94 to '97 was a further reduction in the cost of incremental reliability generation and a review of what customers would actually be outaged for generation resource shortages, which lowered the number in dollars per kwh moving the curve further from 15%, which was the target reserve margin prior, downward toward around the 13.5% range. Those two counteract each other. The lower cost -- I have a lower cost of generation to avoid

Q How long do you anticipate the need for new transmission lines into the area to be delayed because of the unit?

A Let me look, please.

(WITNESS REVIEWED DOCUMENTS)

A I would say at least seven years.

Q My next set of questions are concerning the system reserve margin and how aggregate reserve margin appears in each Southern Company member's individual system. And we're going to be turning to Gulf's response to Staff's Request for Production of Documents Number 21.

MR. MELSON: 21?

MS. JAYE: Yes.

BY MS. JAYE (Continuing):

Q This would be the July of 1997 Economic Study of the Optimum System Planning Reserve Margin for the Southern Electric System. Were the documents provided in Gulf's response to Staff's Request for Production Number 21 used to justify the company's selection of a 13.5% system reserve margin?

A That's correct.

Q Three documents contained in Response 21 appear to be three evolving versions of the same reserve margin study. What are the primary differences in the conclusions reached in each of these three studies?

A That's correct, that's Respondent A. Their capacity is not sufficient to meet Gulf's needs in that year or any subsequent year.

Q Okay. Earlier you had indicated there was an imbalance between generation and load in the Panama City area. Could you clarify and tell what is the approximate amount of this imbalance?

A I'm going to have to draw on memory from a couple of years back when we added it up, but in what we call the Panama City area, back in '96 it was like 75 megawatts. Of course 2002 is six years down the road. We are growing at around 2% a year, so it's going to grow to greater than a hundred.

Q Is the capacity from the proposed Smith CC unit expected to postpone the need for new transmission lines in the Panama City region, and how long would it be postponing them if it were?

A The Smith addition is primarily postponing transmission line improvements into Gulf's territory and from the Pensacola area to the Panama City area. There are some additions, minor additions in the Panama City area that result from the Smith generation. It is a rather large amount of addition; but, yes, it avoids or postpones significantly transmission lines coming to the Panama City area to transport power which it will take the place of.

any of these offers add to or be sufficient for the reliability of the system? Yes.

Q All right.

MS. JAYE: We need to go off the record for a moment, I guess.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Back on the record.

BY MS. JAYE (Continuing):

Q Mr. Pope, if you could clarify the ranking of the different respondents and self-build options as far as their ability to meet electric system reliability and integrity, I'd appreciate it.

A The question of whether these respondents, ignoring the cost of transmission and assuming those transmission improvements being installed and then dealing with that response and ignoring its cost, there are some that can meet the reliability needs, capacity resource needs of Gulf Power Company. There is one that because of the size of its offer would not be sufficient in the year of 2002, which is when we are going to install or want to install this Smith Unit 3 or any of the other respondents, is insufficient to meet Gulf's resource needs because it's a smaller size.

Q Could you tell me if that is Respondent A in the rankings?

Q Focusing in on that fix piece of the statute, just in your opinion, dealing with systems all the time as a layman.

A Before I can formulate an answer, let me just maybe ask a question in clarification because, when you say to ignore cost, there are some costs that directly relate to the reliability of the system but are not associated directly with a response or an offer from a respondent, for instance, transmission improvements.

Q Right.

A Absent the cost, am I to assume that absent those improvements? Because if I ignore the cost of those improvements and ignore his cost but assume that they are there, then I can answer the question, yes; but without those improvements and their -- without their cost and the improvements, then I'd have to say no to some and yes to some.

Q Just for clarification, it would be assuming that any additions that would be necessary to transmission, for instance, would already be in place, already be -- you know, they would be there, or they would be added but you wouldn't factor in the cost of that in ranking the different respondents or the self-build options, would your opinion change?

A And the question, as far as my opinion is, would yeah, sometime, because growth is going to occur, they would be needed. But we tried to keep things down to, if this unit were here or not here, what are the incremental improvements in the planning horizon?

Q As a layman, are you generally familiar with Section 403.519 of Florida Statutes?

A Yes, as a layman.

Q Ignoring any cost implications, would any of the self-build options in RFP projects have sufficiently, in your layman's opinion, provided for Gulf's electric system reliability and integrity as stated in Section 403.519?

A Would you please repeat the question?

Q Certainly. It is rather long. If you ignore any cost implications, just take those out of the mix for a moment, would any of the self-build options in the RFP projects in your layman's opinion have sufficiently provided for Gulf's electric system reliability and integrity as provided for in Section 403.519 of Florida Statutes?

MR. MELSON: Grace, the question is, putting cost aside, would any of these have met that criteria?

MS. JAYE: Yes, electric system reliability and integrity.

MR. MELSON: Okay.

BY MS. JAYE (Continuing):

as opposed to another. Sometimes it's more economical to go ahead and put in a new line although up front it's a lot more dollars, but long-term it's still the most cost effective way.

That is the reason why some things are reconductored or conductor replaced and some are new lines, because it was most cost effective. Also, if you choose to put in a conductor upgrade, there's still a project that may have shown up as a first year addition in one particular option that eventually still has to be built in another, and that's why the different timing. You'll see the different timing in some of the lines because ultimately that particular line will be needed for any of the alternatives. That's why the different timing.

Q Mr. Pope, then would some of these transmission upgrades mentioned in the response to Interrogatory 4, or the additions, depending, have been required regardless of whether the proposed unit was added to Gulf's system?

A Once again, it's the not-for philosophy.

Q Okay.

A If not for this addition or if not for this option, that unit would not be needed in the time frame, the planning horizon.

Q Okay.

A Ultimately I could say on any of these, that

In this response to Interrogatory Number 4, does this contain Gulf's summary of all transmission additions and upgrades required as a result of the self-build options in the RFP project?

A That is correct.

Q Okay. Referring again to POD 4, if you could, please describe briefly the timing of these different additions. You know, I see some are 2002 improvements here for the various transmission lines, and then there's 2009, 2005, et cetera. Why did each option that Gulf reviewed have different transmission system impacts, and why were new lines needed instead of upgrading old lines in certain cases?

A First, and let's talk about any individual analysis, whether it be Respondent A, B, or C or Gulf Smith Unit 3. When you identify a constraint in transmission, there are a number of different alternative solutions, some are just putting up different conductor on existing lines, some are building new lines. The Company always looks far enough out to see whether a particular improvement, such as changing the conductor, would last long enough because that buys you a little bit of capacity but maybe it does not buy you enough long-term; and you have to add up all the -- if you choose one route, you have to add up all those particular costs and find out what their present value is the analysis. So, yes, it does; but that's just by nature of the way we studied it.

Q Okay. This would have been in response to staff's Request for Production of Documents Number 2. There were some documents that were filed which have been returned to the company, and we would like to get those provided again as a late-filed exhibit.

MR. MELSON: This will be confidential late-filed Exhibit Number 2?

MS. JAYE: Yes. We'll give it the title of transmission studies if that comports.

MR. MELSON: Now do you want the -- all the detail supporting studies, or would the summary sheets be sufficient?

MS. JAYE: We can go off the record for a moment and give you a chance to --

(DISCUSSION OFF THE RECORD)

MS. JAYE: Go back on the record.

BY MS. JAYE (Continuing):

Q This Late-filed Deposition Exhibit Number 2, for further clarification for the title will be transmission study summaries.

If you'd turn to Gulf's response to Staff Interrogatory Number 4. There is a listing here of the transmission improvements required. Does this contain --

you'll look at generation, basically between Jacksonville and Mobile, there's a great disparity, and power is going to flow wherever it needs to to get to the load.

As I mentioned earlier, the ideal situation is where you have load is to put a like amount of generation, and that's not the case today; so, therefore, the generation that is in the Mississippi, Gulf Coast, Florida Gulf Coast area, large amounts of it predominantly has to flow toward the east to make up flows in that direction. There are power sales also to Florida which help to cause that, not a major portion because a lot of that comes from north Georgia down through a five hundred kv system.

Q Did Gulf perform any transmission studies on how each of its self-build options in the RFP projects impacted the Southern Company transmission system?

A Could you repeat that one more time?

Q Did Gulf perform any transmission studies on how each of the self-build options in the RFP responses impacted the Southern Company transmission system?

A The transmission analysis that we performed by nature will identify all transmission impacts on the Southern Electric system. Our model contains the entire Southern Company system even though we may only print out those areas that are adjacent to Gulf and including Gulf. The listing of all overload conditions will be listed on amount of generation if you add all that together; and loads and flows that typically go from those areas, the west, toward the east, also add to the aggravation of the transmission system between basically Pensacola or Mobile and the Apalachicola River. As I said, the load in the Panama City area has exceeded Panama City and the -- I guess east of Ft. Walton area has exceeded what's generated there plus other flow. So adding generation in Panama City helps both of those factors, not just necessarily the load generation mismatch.

Q Is part of the mismatch that occurs and part of the reason why putting the generation in Panama City due to the nature of the flow of electricity?

A Yes.

Q Okay. Could you elaborate on that, please?

A The nature of the flow?

Q Flow of electricity, yes.

A Even today, without additional generation being located in the Mississippi, Gulf Coast, Mobile area or to the west of here, the predominant flow pattern is from the west toward the east. In southwest Georgia, south Georgia there is very little generation. Panama City, very little generation. No generation in the Ft. Walton Beach area. There's still considerable amounts of load in those areas. There is a large nuclear plant in Dothan, Alabama; but if different locations. Many of the locations carried with it a tremendous amount of transmission improvements because of not being located near the load. Gulf Power Company today with its existing generation and load is deficient because we own generation facilities already outside of Gulf's territory, so we are already bringing in significant portions of our load. This is further aggravated when you install other generation or newer generation outside of Gulf's territory when there's still a significant amount of load for them to meet. The transmission system, because of the load conditions, would require improvements for all generation not located in the Panama City area. It's because of these costs of the transmission that Panama City was the best location, and transmission improvements drove that, a lot of that.

Q In general then would you agree that there would be a disparity between load and generation in the Panama City area?

A It's not necessarily the load specifically in the Panama City area, although that is a major portion of it. As I mentioned earlier, there is load to be served and there is generation.

Currently, and in the future, generation is located in the Mississippi Gulf Coast area, the Mobile area, also in the Pensacola area, because there is a large to be stressful to the system, we will analyze -- well, not we, but the system operators will analyze the system that day with what they call a security package and determine if there are any problems from a unit out, or the next line out. And they will formulate operating procedures if need be or have a plan of action for moving customers if need be. So planning identifies most of those situations, but sometimes they don't from an operational standpoint. The operating procedures we identify in the planning side of it are provided to and agreed to by the operating folks and in a manual where when those conditions exist they know what to do.

Q Mr. Pope, could you describe why Gulf picked Panama City, Florida for location of a new unit?

A Panama City, Florida, from a transmission -- from a cost basis, is the best. One of the major factors of cost is transmission improvement. A key factor in the power industry is that you have load obligations to meet with generation. It's best to put the generation where the load is. That can't always be done, so you put generation where it can be installed and build transmission facilities to meet the load, to get the power to the load, under reasonable reliability constraints.

In evaluating Gulf's need to have generation on the ground, physical facilities, we looked at a number of

What's the probability that that combination of units and lines would occur? What is the consequence of it? Is it a situation where the next thing that happens brings the system into complete collapse or brings serious concern? What is the severity of it? Does it put a large amount of megawatts or customers at risk? Is it something that is critical for the company's customer service aspects? We look at those risks and consequences -- Oh, also, is there some way we can operate the system differently or at that time to eliminate the problem?

And you take all those into consideration and you make a determination of, yes, we can live with that, or we can afford that risk; or, no, we can't, and we need to spend money to fix it. Many times we have operating procedures that we can take from a planning basis, we'll take these facilities out, we'll run the model again with those conditions, and if it alleviates the problem and that those conditions are not too risky, that's the way we'll operate the system.

That brings me over into the operation of the system. Dynamically, day by day, the system is operated under the conditions that exist at the time. Those may or may not be what we plan the system for. Strange things happen on a day-to-day, real-world basis; but on a daily basis, if the system is in a configuration that is thought for this unit, then don't worry about it.

Q Okay. Could you give a general description of the operation of Gulf's transmission system; that is, the power flow system constraints, generation load imbalances?

A Yes, from a -- I'll give it in two ways.

Q Okay.

A There's a transmission planning aspect of it, and I'll give a brief overview of the operational aspects of it which are very similar. The planning of the Gulf Power Company in the Southern Electric system is conducted now assuming what we call a two element contingency. That's any line and a unit, any auto transformer and a unit, or any auto transformer and a line.

We plan the system at peak conditions. We also look at it at off peak periods to see how unit maintenance occurs, but predominantly we try to meet peak. Peak is when our toughest times from a transmission standpoint occurs. We assume the system over a number of years is at peak. We take critical units out, and then we outage or take out every line with this system and identify all overloaded facilities.

Once that study is completed, that portion of the study is completed and those overloaded facilities and low voltage conditions are identified, we secondly take those conditions and analyze the risk and consequences of them.

say, in Georgia or in Alabama?

A I'm trying to remember because we have some answers to interrogatories -- you referred to the need study -- and we may have to refer to those. There are some impacts to -- in some of the evaluations, particularly the self-build evaluations, the initial self-constructed, which also had cost impacts for lines in the Alabama territory that would be caused by Gulf's generation.

Q Right. I understand that under Interrogatory 4, but how far would Gulf carry that, I guess is what I'm trying to get at. How far away would Gulf carry that in evaluating the impacts on transmission need forced by different additions?

A The only transmission impacts that Gulf would include as a cost would be those that are totally associated with the increment of generation that Gulf would participate or build in any instance, not anything outside that has nothing to do with that.

Q Okay.

A I believe, if I can carry that on just a little bit further to make it clearer, it's kind of like the not-for analysis. If not for this unit, this would not be needed.

Q Right.

A So that's the kind of approach we take. If not

A The prices that Gulf will ultimately come down to with whichever supplier they choose will be no more than what has been assumed. It will likely be less.

Q All right. Mr. Pope, the next series of questions that I wanted to ask you refer to the impact of the proposed unit, other self-build options, and the RFP projects on the transmission system at the Southern Company. When transmission studies are performed concerning the impact of proposed generating unit additions for Gulf, does Gulf perform these studies or does Southern Company?

A Southern Company Services performs the studies.

Q Okay. Are the analyses based on impacts on Gulf Power service territory or on the entire Southern Company system?

A The impacts -- the study will identify impacts to the entire Southern Electric system from any various generation additions. The ones that we are concerned with are the ones that are directly related to generation additions that we would participate -- and the increment of generation that we would participate in.

Q Okay. So the only transmission upgrades that are -- that show up in the need study as being necessary, given the various options and as they are screened, are those that directly affect Gulf, not those that may start, self-build, self constructed evaluation, that particular option was discarded because of the reliability concerns.

That being concluded then we move on to the RFP process where we were provided with offers subject to a separate natural gas transportation RFP issue by Southern Company Services, all of which deal with firm natural gas supply that we evaluated along with our construction of a pipeline. All of these are firm supplies. All the respondents to that RFP that were not firm have been discarded. So all that we are dealing with now are firm natural gas supplies and no secondary non-firm supplies for this unit.

Q Could you tell me, what are the numbers of suppliers that you are dealing with now?

A I believe we still have four suppliers that we are continuing to talk with or keeping negotiations open with.

Q Okay. Have you entered into final negotiations with any of these suppliers yet?

A Not to my knowledge at this time.

Q Would you expect that the price that is finally accepted by Gulf in negotiations with these four suppliers would be comparable to or cheaper than the prices that were used by Gulf in evaluating the different proposals in the need study itself.

MS. JAYE: Okay. Could we go off the record a minute, please?

(DISCUSSION OFF THE RECORD)

MS. JAYE: Back on the record.

BY MS. JAYE (Continuing):

Q Does the information provided in the need study include the most up-to-date information that Gulf has received on purchase of capacity for natural gas to fire the proposed unit?

A Yes, in portions of the need study. I want to make sure that we're clear. You asked a question about the latest and the final analysis and evaluations.

Q Yes.

A I need to explain the phases of our evaluation that dealt with different natural gas assumptions. For instance, what we did in the initial phase, the self-build evaluations, that were concerned with self-construction options, were to look at a number of various natural gas supply alternatives. One was the natural gas pipeline from the Atmore area. Another one that has a more attractive economic picture is to use release firm or a non-firm type of gas transportation. That particular option of the release firm or non-firm type of transportation was very comparable to the natural gas pipeline; however, it's not firm, it's not reliable. And at the conclusion of the but Exxon permitted a pipeline, about a 58-mile pipeline, from the Destin Dome wells, a number of wells that would feed into this pipeline and bring that gas on shore into the Mobile area. That's the Destin Dome pipeline.

Q On Page 57 there is a discussion of Gulf constructing its own pipeline to the Atmore, Alabama area. What is in Atmore, Alabama? Is there a major gas transmission line there?

A There are two major natural gas pipelines, transmission lines that are in the Atmore, Alabama area. One is owned by Florida Gas Transmission, the other by Koch. That's K-o-c-h.

Q Referring now to Page 73 of the need study, does Gulf Power have a firm transportation agreement with FGT?

A Not at this time.

Q Okay. Does Gulf Power plan on purchasing 100% firm capacity off the secondary market if it does not get that capacity from FGT?

A I don't believe so. Our entire focus is from a natural gas supply strategy, and all efforts have been secure, and we've been involved in conversations and negotiations with various suppliers for a firm natural gas supply. We have had offers of firm natural gas supply. I am not aware and don't believe that we have even considered a secondary non-firm supply.

A Go ahead.

Q All right. Now these interrogatories appear to itemize capital and O&M cost for SCR system and closed cycle cooling tower system. Do you expect Gulf Power to seek recovery of these costs through the environmental cost recovery clause?

A I don't know. Once again, our focus in this proceeding is for cost effectiveness purposes, and I'm not certain as to what may come as far as recovery for these.

Q Okay.

MS. JAYE: Would it be all right if we took about a two-minute break?

(BRIEF RECESS)

MS. JAYE: Ready to go back on the record.

BY MS. JAYE (Continuing):

Q On Page 56 of the need study there are some discussions of various gas suppliers and gas transmission possibilities. Could you please explain, what is Destin Dome pipeline?

A There is an area offshore of the Alabama and Florida, northwest Florida coast that is commonly referred to as the Destin Dome. It's a large area out in the Gulf where there are significant natural gas supplies, and they've called or dubbed that the Destin Dome.

I forget if it's been three or four years ago, discharge canal is going to depend on the ambient temperature or ambient conditions at any time. But it means that whatever the situation is at the time, if you take the Smith 3 cooling water design, you will slightly decrease what otherwise would be there without it.

Q Okay. You answered both the questions. I now have four questions referring to Gulf Power's response to staff's Request for Production of Documents Number 18.

A Okay.

Q In response to this request for production, Gulf provided a letter to Mr. Greg Worley of the U.S. EPA in Atlanta, from G. Dewayne Waters. This letter is dated April 6, 1999. Mr. Pope, are you familiar with this letter?

A I'm not intimately familiar with it, but I am aware of it and kind of know what it says.

Q Okay. Do you know if Gulf Power has received a response from the EPA yet regarding --

A I'm not aware of any formal response yet. I believe this is just a letter of notification to them of what we plan to do.

Q Okay. The next question is referring to Gulf Power's response to staff's Interrogatories Number 23 and 24. Give you a chance to look those up quickly.

(WITNESS REVIEWED DOCUMENTS)

strategy, go on and put SCR. I mean that would be different than -- We may not have a choice. They may tell us. We don't think that's going on happen. We think there's a high likelihood if not a very positive attitude or likelihood that we are going to have the NOx offset accepted without SCR.

To answer your question as far as having to, we'll -- Gulf Power Company is going to do whatever is required of it to meet all state, federal laws and regulations with regard to the environment.

Q My next two questions are taken from Gulf Power's response to staff's Interrogatory Number 25. In this interrogatory the response states in part, "Because the blow down from Smith Unit 3 will be taken from the cold side of the cooling tower, there will be a slight decrease in the overall temperature of the discharge water entering West Bay."

My first question is when Gulf Power claims a slight decrease in the overall temperature of the discharge water will result, does a slight decrease refer to a decrease from the current temperature of the discharge water?

A It means a slight decrease as opposed to without the Smith Unit 3 being there, or without -- with some other means of cooling because the temperature coming out of the

(DISCUSSION OFF THE RECORD).

MS. JAYE: Let's go back on the record now.

BY MS. JAYE (Continuing):

Q Okay. I have three -- I'm sorry, the following two questions will refer to the first full paragraph on Page 76 of the need study, the paragraph which begins, "As mentioned above."

A Okay, I found that paragraph.

Q Okay. Does Gulf Power plan to install the SCR only if the low NOx burner technology and GNOCIS fail to reduce the NOx emissions at Smith Unit 1 to approximately 28 hundred tons per year?

A The determination of environmental compliance is going to be determined by the environmental folks, and I think it's safe to say that it's our strategy and our proposal that the offset by having a total NOx reduction strategy at Smith should not only be accepted but should be, I guess, welcomed. It's a total -- it actually reduces overall NOx emissions, and we believe, pretty confidently that that will be accepted so that the burners and the GNOCIS would be accepted and installed.

Now you asked, you know, would we only do this if we didn't meet it? Well, the environmental -- the environmental process may go or change things to where they say, that's all well and good, but we don't accept your

SCR. The GNOCIS system and the burners cost about two million dollars. The SCR cost about three million plus about a million dollars a year in O&M. In a conservative nature, we put the SCR cost, both capital and O&M in the cost effectiveness analysis knowing that the better alternative would probably be accepted at a lesser cost, so we have erred in the conservative nature of actually a higher cost, it's an either or. So, no, it's, not specifically included, but it's well covered.

Q Okay. Mr. Pope, there would be a reduction of emissions, according to your analysis, if a low NOx burner technology and the GNOCIS system are used on the Smith unit. Could you go into some detail and explain what the current emissions are and how the low NOx burner technology and GNOCIS will help reduce that in relation to the SCR that is included in the cost effective analysis for the Unit 3?

A I can respond to that in, I guess, an overview or overall fashion. I cannot tell you the exact NOx emissions out of the existing units, Smith 1 and 2.

Q Right.

A But we can take a hypothetical if you'd like and show how this would work.

MS. JAYE: Could we go off the record a moment, please?

in reference to Gulf Power's response to Staff Interrogatory Number 22. About midway down Gulf's response there is a sentence which reads, "Gulf Power will accomplish the reductions through installing low NOx burner technology and GNOCIS, a generic NOx control intelligent system on Unit 1." Have you located that sentence?

A Uh-huh.

Q Okay. Are the costs associated with the low NOx burner technology and GNOCIS included in Smith Unit 3's cost estimate?

A Not specifically.

Q Okay.

A We -- in looking at the cost effectiveness of the Smith option, you are either going to install selected catalytic reduction equipment for NOx or some other alternative, which in this case would be the low NOx burners and the GNOCIS system on Smith 1. The selected catalytic reduction system, or SCR which I'll refer to from here on out, will reduce the emissions of Smith 3, the new unit; but the overall NOx emissions from Smith plant will go up.

Gulf's strategy with this new addition was to offer a little better alternative; and that is, to reduce the NOx emissions from Smith 1 to the extent that it more than accounted for the emissions of the new unit without

Q Okay. Returning again to the table in response to POD 16, staff noted that Respondent A has under commodity price basis column Henry Hub plus 4%. Does this indicate that Respondent A's bid was evaluated based upon a natural gas commodity forecast which is 4% higher than the Henry Hub index itself?
A We have no idea of knowing what assumption caused that respondent to add a 4% premium to his Henry Hub index. That was his quote to us.
Q Okay.
A Their quote to us.
Q Okay. Looking at the table again, the self-build Smith option, commodity price adjustment is a negative .06. Does this indicate that the self-build Smith option's bid was evaluated based upon natural gas commodity forecast which is six cents less than Henry Hub?
A That's correct.
Q Okay. In looking at the respondents indicated in the column, if two alternatives which appear here have the same commodity price basis and the same commodity price adjustment, you know, Column A and Column B are the same, would these alternatives have the same natural gas price forecast?
A For commodity, yes.
Q Okay. The next three questions are going to be

A Between the self-build evaluation, which were self-constructed options only, and the RFP response, there were different opportunities from a natural gas supply that came available. In the initial phase, which is your self-build, self-constructed evaluation, the primary winner, I guess, or primary cost effective natural gas supply dealt with construction of a natural gas pipeline of some miles to the Smith plant that we would be willing to under take. It carried with it a certain set of assumptions. In the RFP evaluation, with the same Smith construction, it had different natural gas supply opportunity, not the construction of the pipeline; and so it carries a different set of assumptions.

Q Did the self-build Smith option then include Gulf self-construction of pipeline to carry natural gas down to the proposed plant?

A The self-build option, the initial phase?

Q Yes.

A Yes, it did.

Q Okay. And --

A In the form of constructing a pipeline from near Atmore or Brewton, Alabama, to the Smith site.

Q And the RFP Smith option then included having a third party construct a pipeline to carry the gas?

A That is correct.

or in eastern Texas, but I can give you a better answer if allowed to.

Q Okay. We'll move on then.

For purpose of evaluating the most cost effective alternative, how does Gulf Power define "Commodity Price Adjustment" as found in the last column?

A The commodity price adjustment are things that will be added to or should be added to a commodity price because of a premium, for instance. People may want to charge you a premium from, say, Henry Hub or some other basis place to a certain point where you are going to take it off the natural gas pipeline. There may be some O&M or compression charges that may go along with that because of compression services that go in between that point and there, not transportation, but compression services, or other increments that would be added to that fuel commodity not associated with transmission, just that are associated with the fuel commodity itself.

Q Noticing the numbers that fall under the commodity price adjustment in the response to Staff Interrogatory 16, some of them are in brackets. What does that indicate?

A That's a negative number.

Q Okay. How does Gulf Power distinguish between the self-build Smith option and the RFP Smith option?

effective alternative, how does Gulf Power define "commodity price basis?"

A Where is that in the --

Q It's at the very bottom. It's one of the middle columns. It's titled "Commodity Price Basis."

A Oh, okay. In either the self-build options or in the offers, people are given the opportunity to choose an index basis. Like in oil it could be the Portland, Oregon received -- has received Number 2 oil price, or it could be the Number 6 oil price as received at Savannah Port. For natural gas these are on-shore type of indices, and there are some common ones. In this area of the country, one of the most common ones is Henry Hub, and that's where you base -- you can say, okay, as-delivered price to that point plus all transportation, taxes, O&M, and other things; but they have to give a basis for what commodity price point they want things to be delivered to, to use as a basis for delivery point.

Q Okay. Could you please explain where Henry Hub is in relation to Gulf Power Company? Is this something in the midwest or --

A I can't give you that exactly, but I could provide it later.

Q Okay.

A I believe -- I believe it's either in Louisiana

MR. MELSON: Could you list again what it is you are looking for?

MS. JAYE: Certainly.

MR. MELSON: It's the fuel assumptions for --

MS. JAYE: What we would like is information, the confidential information which would be in response to staff's Request for Production of Documents Number 15.

THE WITNESS: Okay, that's '95 IRP, 1996 update?

BY MS. JAYE (Continuing):

Q Right, 1997 IRP update, 1997 capacity solicitation, 1998 full IRP, and 1999 IRP update. And what staff is looking for are documents which the fuel panel relied upon to create the Southern Company generic fuel price forecast which was used in those years.

A Oh, okay.

MR. MELSON: Off the record a minute.

(DISCUSSION OFF THE RECORD)

BY MS. JAYE (Continuing):

Q I have six questions -- Back on the record. I'm sorry.

I'm now going to ask six questions in response to Staff Interrogatory Number 16.

A Okay.

Q For purposes of evaluating the most cost

A The assumptions on Page 51 of the need study are based on 1996 financial assumptions. They're also reported in response to Interrogatory Number 13 along with the '97 and '98 information which we relied upon.

Q Okay. And the financial assumptions for 1996 and 1997, we note that Gulf used DRI Trendlong forecast to project out financial information, but in 1998 the company switched to Regional Financial Associates. Do you know why this was done?

A I don't know the specific reason why that was done.

Q All right. Mr. Pope, I'm now going to ask you some questions in order to clarify responses received regarding Gulf's fuel price forecast assumptions. Do you have the documents which the fuel panel relied upon to create the Southern Company generic fuel price forecast used in the 1995 full IRP, 1996 IRP update, 1997 IRP update, 1997 capacity solicitation, 1998 full IRP, and the 1999 IRP update?

A No, I don't have. I have some '98 information with me.

Q Okay. Could you please provide this information in a late-filed exhibit? We will call this the IRP exhibit. We'll amend that name and call it IRP fuel exhibit.

Q Do you know the benchmark for the consumer price index or any of those things that went into the need study?

A No, I don't. Not specifically, no.

Q Mr. Pope, do you know the year that the rates applied these CPI, GDP, et cetera? Were they using '97, '98?

A Not specifically, no, but I do know they used the latest information. I don't know if it would be third quarter or second quarter information from those sources.

Q In 1996 and 1997 Gulf used the DRI Trendlong Forecast, but in 1998 the company used the Regional Financial Associates. Could you explain why Gulf switched services?

A Are you talking about the -- you're talking about forecast information there, the load forecast?

Q Yes.

A I do not know. If you're talking about load forecast, that would be Mike Marlar.

MS. JAYE: Could we go off the record for a moment?

(DISCUSSION OFF THE RECORD)

MS. JAYE: Let's go back on the record then.

BY MS. JAYE (Continuing):

Q Mr. Pope, could you please tell what year these assumptions on Page 51 of the need study are based on?

in five years. These people in Atlanta gather this information. They're analyzing it and trying to put some regional factors into place for the southern, southeastern United States to come up with what they think are the reasonable escalation and construction -- or inflation and construction escalation would be.

The inflation comes directly from those people in Atlanta. The construction escalation is derived by the people in Southern Company Services engineering in Birmingham. They take basically the information from the economic people in Atlanta, they look at what recent equipment and salary or labor rate increases have been, and they come up with a construction escalation. So that's the how from what I know.

Q Okay. Do you have any idea of whether the escalation rate of 3.02% that is a product of the people, Southern Company Services in Atlanta was derived from Moody's or from DRI, do you know which they rely on?

A They don't rely on just one, they rely on a number of indicators and factors that are provided and brought together and discussed, and it's not just one, no. It's not one.

Q Do you know what was the benchmark for the general inflation rate that was used in the need study?

A No. No, I don't.

you're consistent. And the reason 13 and a half percent was selected as opposed to 12, which is our center range, is because we looked at this as a Southern System type of evaluation, for cost effectiveness purposes.

Q Mr. Pope, if you could please turn to Page 51 of the need study.

A Okay.

Q On this particular page, the Company reports a construction escalation rate of 3.02% and a general inflation rate of 2.78%. Could you please explain how these rates were derived?

A The details of how I -- I can just give an overview.

Q Okay.

A We have a group of people in Atlanta with Southern Company Services that put together, I guess, all of the economic indicators from all economic sources. I can't remember if these are all the right ones now, but the DRI and people similar, Moody's and Standard and Poors. They all have predictions of what near-term and long-term bond rates would be and what certain other earnings would be. They also give indicators of your general deflators, your inflation, your escalation, your other indicators that are expected because of what the economy is doing at any point in time and what they expect it to do, particularly self-build and the authorized ROE of Gulf which ranged between 11 and 13% during the time the valuations were done?

A As I mentioned earlier, the view of these analyses from the very beginning was from a Southern view as far as cost effectiveness, try and see what it brings from a Southern Electric System or Southern Company type view. We're determining cost effectiveness of these alternatives, and Gulf's self-build option, Smith Unit 3, is part of it. It's cost effectiveness, and the reason that we don't necessarily think that we need to do it based on Gulf's allowed return, the center range is 12% which allows us to earn between 11 and 13% before refund or before other things happen is because it's not an issue of recovery or what the rates would be. We're not looking at what rate impacts would be which we would analyze the allowed rate of return. It's an issue of cost effectiveness, and that's why it's really, even though it is different, it's not invalid or unreasonable; and it is a correct way of analyzing cost effectiveness, as long as you treat everyone consistent. Like I said, it actually gives Gulf's self-build option a slight disadvantage by assuming a higher rate of return, but that's why. It's not -- the cost effectiveness evaluation does not necessarily have to be predicated on your allowed rate of return but as long as the discount at which you discount in present worth your numbers. The rationale there was we could use 12 and a half percent or 13% or 13 and a half or 14%, and when you're talking about evaluating things all at the same time, you want to use a consistent basis more than anything; and we chose the Southern System because it was more or less a Southern type of an evaluation.

We carried that philosophy and that assumption forward into, when we moved to the 1998 assumptions and did the RFP evaluations. Understanding that the 13 and a half percent equity rate would raise the cost, the capital -- revenue requirement stream for Gulf self-build option. It also lowers the discount rate, but if you do the same for Gulf self-build as you do for all others, you are still treating everybody equal; and actually you are giving Gulf a hit on its self-build by its present worth revenue requirements being higher. And it was still considered to be a Southern evaluation, and that's why we did it.

MS. JAYE: We need to go off the record for a moment.

(DISCUSSION OFF THE RECORD)

BY MS. JAYE (Continuing):

Q Mr. Pope, if you could please explain the relationship between the 13.5% that you used as a cost of equity for evaluating all of the Gulf proposals in the cost effectiveness of this project?

A That's correct. That's the calculation for calculating the after-tax weighted average cost of capital, and that is what we used.

Q Okay. What is the overall cost of capital factored into the calculation of the cost effectiveness of this project now?

A For cost effective purposes, it's still the same. It's 8.465%. That's according to the '98 -- 1998 financial assumptions.

Q Okay. So Gulf used the 1998 data to calculate the overall cost of capital?

A Correct. Correct, that's for all of those RFP responses which is Gulf self-build and all of the offers that came out of the RFP.

Q Would you please explain why Gulf used a 13.5% as the cost of equity in its financial assumptions?

A The analysis and evaluations were performed by Southern Company Services, and the initial phase, which was the self-build option phase evaluation, we -- because we were looking at participating in sister units and because this is a Southern System type of evaluation, we at that time deemed that we would use the Southern System assumed rate of return to calculate the after-tax weighted average cost of capital. The key element there for that factor is

A Not the early or initial self-build evaluations. As I mentioned earlier, the final determination, as you asked, the final determination of cost-effective alternatives were those that were evaluated in the RFP process. All of those in the RFP process use the 1998 assumptions. The self-build analysis, which was the initial phase of identifying Gulf's self-build option or best self-build option, used the '97, 1997 financial assumptions because it was conducted starting in 1997; and that involved the evaluation of about four self-construction options. And we went through that process using those and have not gone back at this time and updated those because, once you've gotten to that point and moved to where of all your construction options this one is the one you want to move forward with and see if there are other alternatives, then there is no need to go back and do that. Now Smith 3, which was the selected self-build option was carried forward, it has been updated, but all of those others we evaluated were not.

Q In Gulf's response to staff POD Number 11, we are told, "See the response to Production of Documents Number 10 and the sample calculation contained in response to Interrogatory 14b." Looking now at interrogatory 14b, I'd like for you to please explain, is this the way that Gulf actually calculated the discount rate used in evaluating

Q In Gulf's response, there is the statement that unfortunately the need study only included the financial assumptions from 1996, and it goes on to say that Gulf will provide all three sets of financial assumptions to demonstrate their similarity and consistency. My first question regarding these, is upon which of these three sets of data did Gulf base its final evaluation of the cost effectiveness of the self-build option?

A It would be the financial assumptions for 1998.

Q Okay. Did Gulf use the same financial assumptions in evaluating all of these alternatives?

A In the final evaluations?

Q Yes.

A Yes.

Q Has Gulf revised all of the cost estimates of the project to reflect the most recent rates as of 1998?

A I'm not sure I understand the question.

Q Could we go off the record for a minute?

A Sure.

(DISCUSSION OFF THE RECORD)

MS. JAYE: Go back on the record.

BY MS. JAYE (Continuing):

Q I'll ask the question again. Has Gulf revised all the cost estimates of the project to reflect the most recent rates as of 1998?

Company power plant for six years. I was then given the opportunity to be supervisor of system planning up until about May of 1993 when I became the coordinator of bulk power planning.

Q In the position as coordinator of bulk power planning, do you deal with a lot of the need determinations and need filings for Gulf and by extension Southern?

A This is our first one in many, many years; but in my position it would be the position that's normally associated with need determinations for the company.

Q Okay. So you're the person to ask questions concerning most of the overview of need and need determination cases?

A Need planning aspects, yes.

Q Okay. Very good.

I'm going to ask you a few questions now regarding Issue Number 6 from the issue identification conference. The first one is to clarify the responses that staff received regarding the financial assumptions backing Gulf's responses. Do you have a copy of the Gulf responses to staff interrogatories with you?

A I certainly do.

Q Okay. If you would please turn to the response to Interrogatory Number 13?

A I have it.

Whereupon,

WILLIAM F. POPE

was called as a witness by the FPSC Staff and, after being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. JAYE:

Q Good morning.

Nancy, could you please insert all the usual stipulations language there? Thank you.

Good morning, Mr. Pope.

A Good morning.

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

A William F. Pope, Gulf Power Company.

Q And what is your current position with Gulf Power Company?

A I'm the coordinator of bulk power planning.

Q Okay. And have you held other positions previously with Gulf Power?

A Yes, I have.

Q What are those positions?

A I've been a plant engineer on my first assignment with Gulf Power Company. I was a superintendent of engineering and administration at another Gulf Power

INDEX OF EXHIBITS

* * ● *

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STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

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APPEARANCES:

GRACE A. JAYE, ESQUIRE, FPSC, 2540 Shumard Oak Boulevard, Suite 370, Tallahassee, Florida 32399-0850.

RICHARD D. MELSON, ESQUIRE, Gulf Power, Hopping, Green, Sams & Smith, 123 South Calhoun Street, Tallahassee, Florida 32301.

RUSSELL BADDERS, ESQUIRE and JEFFREY STONE, ESQUIRE, Gulf Power, Post Office Box 12950, Pensacola, Florida 32576.

GAIL KAMARAS, ESQUIRE, LEAF, 1114 Thomasville Road, Suite E, Tallahassee, Florida 32303.

ALSO PRESENT:

EVA SAMAAN, FPSC Staff.

MICHAEL HAFF, FPSC Staff.

ANDREW MAUREY, FPSC Staff.

WAYNE MAKIN, FPSC Staff.

TODD BOHRMAN, FPSC Staff.

ROBERT MOORE, Gulf Power.

* * * *

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of Gulf Power Company) DOCKET NO.990325-EI
to determine need for proposed)
electrical power plant in Bay County)

DEPOSITION OF: WILLIAM F. POPE

TAKEN AT THE INSTANCE OF: FPSC Staff

DATE: Monday, May 10, 1999

TIME: Commenced at 9:00 a.m.
Concluded at 12:00 Noon

PLACE: FPSC
2540 Shumard Oak Boulevard
Room 362
Tallahassee, Florida

REPORTED BY: NANCY S. METZKE, RPR, CCR

C & N REPORTERS
REGISTERED PROFESSIONAL REPORTERS
POST OFFICE BOX 3093
TALLAHASSEE, FLORIDA 32315-3093
(850) 697-8314 / FAX (850) 697-8715

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Commission Requested Analysis - - TOTAL Dollars

574 mw

	Respondent/Alternative	Gen. & Trans. Accum. PW. Total Cost (000$)	Total Cost Above Self Build (000$)
1	20 Year Self-Build	49,533,716	
2	Respondent B - CT Proposal (20 Year Pricing)	49,654,712	120,997
3	Respondent B - CC Proposal (10 Year Pricing)	49,661,133	127,417
4	Respondent C	49,670,498	136,782
5	Respondent B - CT Proposal (10 Year Pricing)	49,674,115	140,399
6	Respondent B - CC Proposal (7 Year Pricing)	49,675,986	142,270
7	Respondent A - 2 Cogen Facilities	49,676,695	142,979
8	Respondent B - CC Proposal (20 Year Pricing)	49,683,824	150,108
9	Respondent B - CT Proposal (7 Year Pricing)	49,686,555	152,839
10	Respondent C Proposal with Fixed and Levelized Energy Price	49,727,135	193,419

Commission Requested Analysis - - TOTAL Dollars

540 MW

	Respondent/Alternative	Gen. & Trans. Accum. PW. Total Cost (000$)	Total Cost Above Self Build (000$)
1	Smith Unit 3 - 20 year	49,538,320	
2	Respondent B - CT Proposal (20 Year Pricing)	49,654,712	116,392
3	Respondent B - CC Proposal (10 Year Pricing)	49,661,133	122,813
4	Respondent C	49,670,498	132,178
5	Respondent B - CT Proposal (10 Year Pricing)	49,674,115	135,794
6	Respondent B - CC Proposal (7 Year Pricing)	49,675,986	137,666
7	Respondent A - 2 Cogen Facilities	49,676,695	138,374
8	Respondent B - CC Proposal (20 Year Pricing)	49,683,824	145,504
9	Respondent B - CT Proposal (7 Year Pricing)	49,686,555	148,234
10	Respondent C Proposal with Fixed and Levelized Energy Price	49,727,135	188,814

Summary of Late-filed Exhibit #4 from
Deposition of William Pope

(Non-Confidential)

Florida Public Service Commission
Docket No. 990325-EI
GULF POWER COMPANY
Witness: William F. Pope
Deposition Exhibit No. 3

HISTORY AND FORECAST OF SOUTHERN EQUIVALENT AVAILABILITY FACTOR 1994 THROUGH 2004

YEAR	ACTUAL HISTORY	FUTURE PROJECTION
1994	84.87%	
1995	87.08%	
1996	85.75%	
1997	86.39%	
1998	83.69%	
1999		(1)
2000		(1)
2001		(1)
2002		(1)
2003		(1)
2004		(1)

(1) The Southern electric system does not project Equivalent Availability Factors (EAF) for its units. Southern uses Equivalent Forced Outage Rate (EFOR) in consideration of reliability.

Exhibit A.5 - New Peaking CT Failure Rates and Reliabilities

Run Time Hours	Failure Rate	Hourly Reliability	Cumulative Reliability
1	0.013807	0.986288	0.986288
2	0.008725	0.991313	0.977720
3	0.006670	0.993352	0.971220
4	0.005513	0.994502	0.965881
5	0.004756	0.995256	0.961298
6	0.004215	0.995794	0.957255
7	0.003806	0.996202	0.953619
8	0.003484	0.996522	0.950303
9	0.003222	0.996783	0.947245
10	0.003005	0.996999	0.944403
11	0.002821	0.997183	0.941743
12	0.002663	0.997340	0.939238
13	0.002526	0.997477	0.936869
14	0.002405	0.997598	0.934618
15	0.002297	0.997705	0.932474
16	0.002201	0.997801	0.930423

NOTE: Run time is measured in hours, and failure rate units are number of forced outages per service hour.

Exhibit A.6

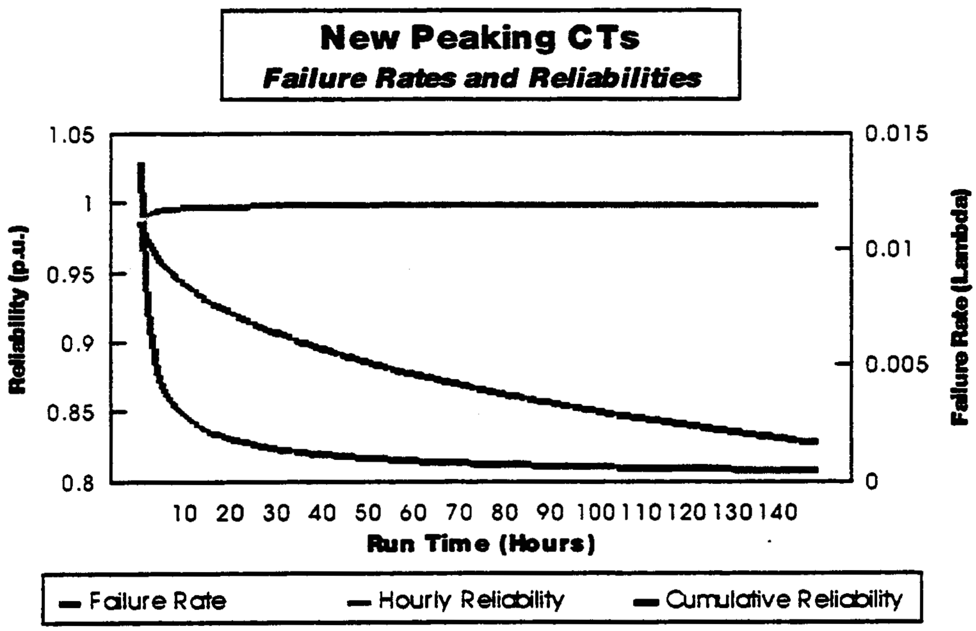


Exhibit A.3 - Other Peaking CT Failure Rates and Reliabilities

Run Time Hours	Failure Rate	Hourly Reliability	Cumulative Reliability
1	0.027588	0.972789	0.972789
2	0.017435	0.982716	0.955976
3	0.013330	0.986758	0.943317
4	0.011018	0.989042	0.932980
5	0.009505	0.990540	0.924154
6	0.008424	0.991611	0.916402
7	0.007607	0.992422	0.909457
8	0.006963	0.993061	0.903147
9	0.006441	0.993580	0.897348
10	0.006007	0.994011	0.891974
11	0.005640	0.994376	0.886958
12	0.005324	0.994690	0.882248
13	0.005049	0.994964	0.877805
14	0.004807	0.995204	0.873595
15	0.004593	0.995418	0.869592
16	0.004401	0.995609	0.865774

NOTE: Run time is measured in hours, and failure rate units are number of forced outages per service hour.

Exhibit A.4

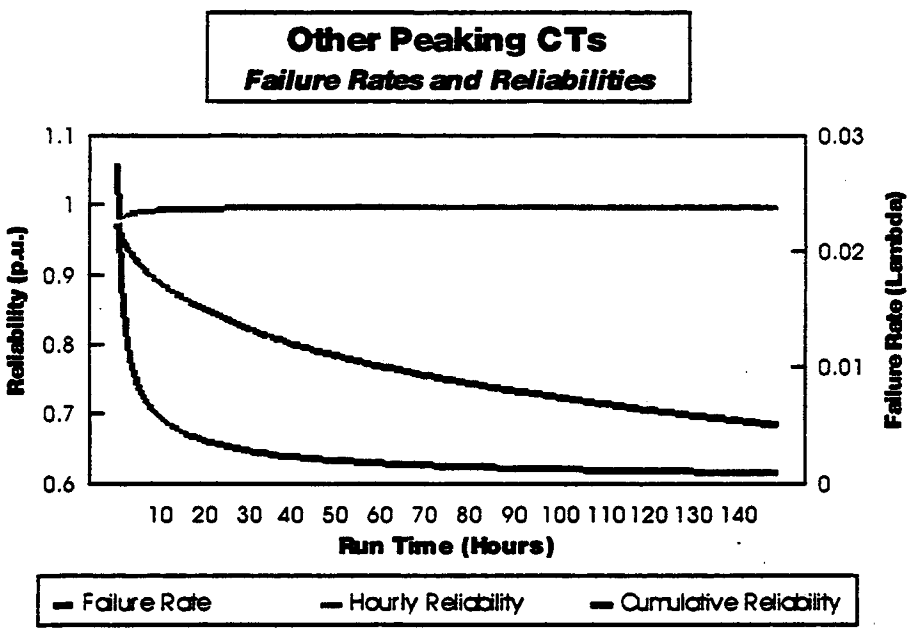
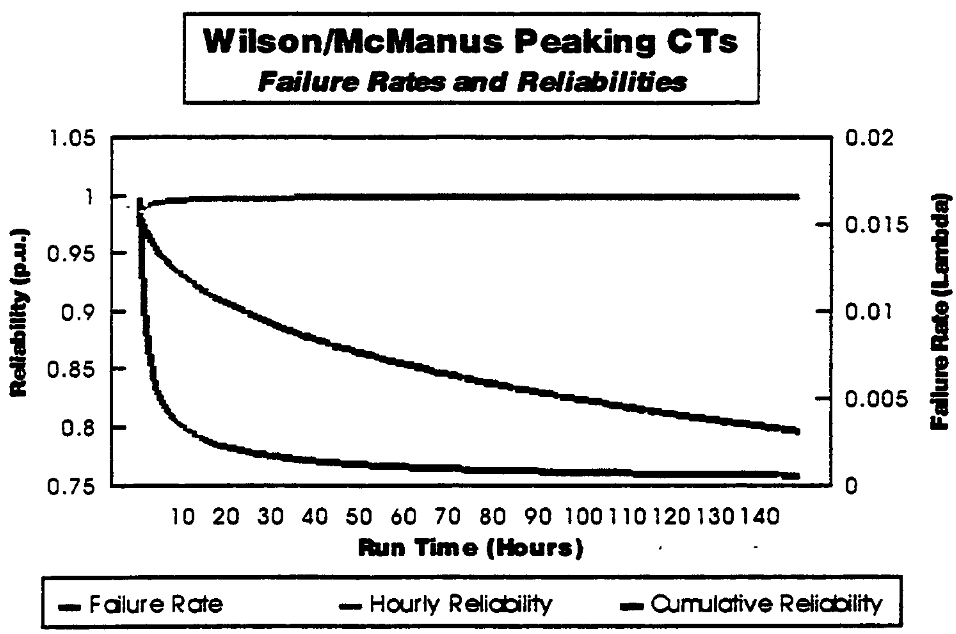


Exhibit A.1 - Wilson / McManus Peaking CT Failure Rates and Reliabilities

Run Time Hours	Failure Rate	Hourly Reliability	Cumulative Reliability
1	0.016558	0.983578	0.983578
2	0.010464	0.989591	0.973340
3	0.008000	0.992032	0.965584
4	0.006613	0.993409	0.959220
5	0.005704	0.994312	0.953764
6	0.005056	0.994957	0.948955
7	0.004565	0.995445	0.944632
8	0.004179	0.995830	0.940693
9	0.003865	0.996142	0.937064
10	0.003605	0.996402	0.933692
11	0.003384	0.996621	0.930538
12	0.003195	0.996810	0.927570
13	0.003030	0.996975	0.924763
14	0.002885	0.997119	0.922099
15	0.002756	0.997248	0.919562
16	0.002641	0.997363	0.917136

NOTE: Run time is measured in hours, and failure rate units are number of forced outages per service hour.

Exhibit A.2



SOUTHERN COMPANY

hour, the running reliability for each hour, and the cumulative running reliability through that hour for peaking CT missions of up to 16 hours (tabulated) and up to 150 hours (graphed). Note that time is measured in hours, and failure rate units are number of forced outages per service hour.

Wilson/McManus $\lambda_t = 10^{[-0.66213 \times \log(t) - 1.78099]}$

Other CTs $\lambda_t = 10^{[-0.66207 \times \log(t) - 1.55928]}$

Peaking CT running reliability is the probability of the CT completing its mission. The probability of a CT running through each individual hour of its mission is found by using the following equations:

New CTs $R_t = e^{-(\lambda_t)(1)}$

$$= e^{-(10^{[-0.66226 \times \log(t) - 1.85989]}) \times (1)}$$

$$= e^{-10^{[-0.66226 \times \log(t) - 1.85989]}}$$

Wilson/McManus $R_t = e^{-(\lambda_t)(1)}$

$$= e^{-(10^{[-0.66213 \times \log(t) - 1.78099]}) \times (1)}$$

$$= e^{-10^{[-0.66213 \times \log(t) - 1.78099]}}$$

Other CTs $R_t = e^{-(\lambda_t)(1)}$

$$= e^{-(10^{[-0.66207 \times \log(t) - 1.55928]}) \times (1)}$$

$$= e^{-10^{[-0.66207 \times \log(t) - 1.55928]}}$$

The probability of a peaking CT running from a start at time t=0 through different points of its mission is the cumulative product of the running reliabilities for each hour to that point as shown below:

Cumulative $R_t = (R_1 \times R_2 \times R_3 \times \ldots \times R_t)$

For these three types of CT characteristics modeled - Wilson/McManus CTs, Other CTs, and New CTs - the following tables and graphs, Exhibits A.1- A.6 show failure rate values for each

Combustion Turbine Failure Rates and Reliabilities

ITEM # 1

Following a start failure or a forced outage event, the probability of the CT being in the available state on each day following the event:

Day	New CTs Probability Available	Wilson/McManus Probability Available	Other CTs Probability Available	
Day 1	72%	89%	89%	
Day 2	9%	4%	3%	
Day 3	9%	3%	4%	
Day 4	10%	4%	4%	(100% Totals)

Note: Some high-impact, low-probability events could last longer than four days.

ITEM # 2

Peaking CT starting reliability is defined as the probability that the machine will be brought on-line within 30 minutes of the time that it is called upon to run.

New CTs Starting Reliability	Wilson/McManus Starting Reliability	Other CTs Starting Reliability
98%	98%	98%

ITEM # 3

Peaking CT failure rate (λ) is estimated to be a function of run time (t) during each individual mission. This means that the failure rates for the CTs change for each hour of their mission as shown by the equations below:

New CTs $\lambda_t = 10^{[-0.66226 \times \log(t) - 1.85989]}$

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SOUTHERN COMPANY

An Economic Study
of the
Optimum System Planning Reserve Margin
for the
Southern Electric System

APPENDIX A

July 1997

V. SUMMARY

In summary, after a very thorough and detailed analysis of the current and near-term projected generation reliability state of the Southern electric system, it is concluded that the system should transition from the existing minimum 15% system planning reserve margin to a minimum 13.5% system planning reserve margin by 1999. There are two significant changes that contributed to this result (1) modeling techniques which decreased the EUE and LOLH output from the Monte Carlo Frequency and Duration (MCFRED) model compared to previous studies; and, (2) reducing the 1989/1990 cost of EUE estimate from $8.72 per kilowatt-hour to $4.34 per kilowatt hour, both in 1996 dollars.

However, it should be noted that an economic analysis is only one piece of information used to determine an optimum generation reliability level. No decision of this importance should be made solely with a series of mathematical models. Industry experience, system operations input, perceptions of acceptable risks, and an understanding of the strengths, weaknesses, and biases of the mathematical models must all be considered in determining the amount of capacity which should be added to the system in the late 1990s and the early 2000s.

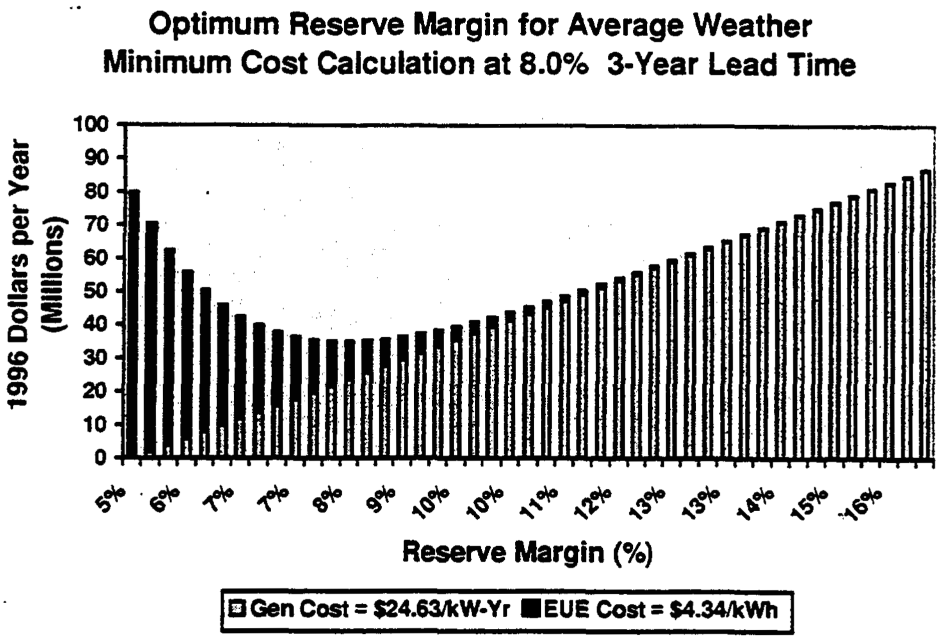


Exhibit IV.E1

Exhibit IV.D1

Cost of EUE ($/kWh)	*Reserve Margin*
$2.18	12.00%
$4.36	13.50%
$8.72	15.00%
$13.07	16.00%
$15.25	16.25%

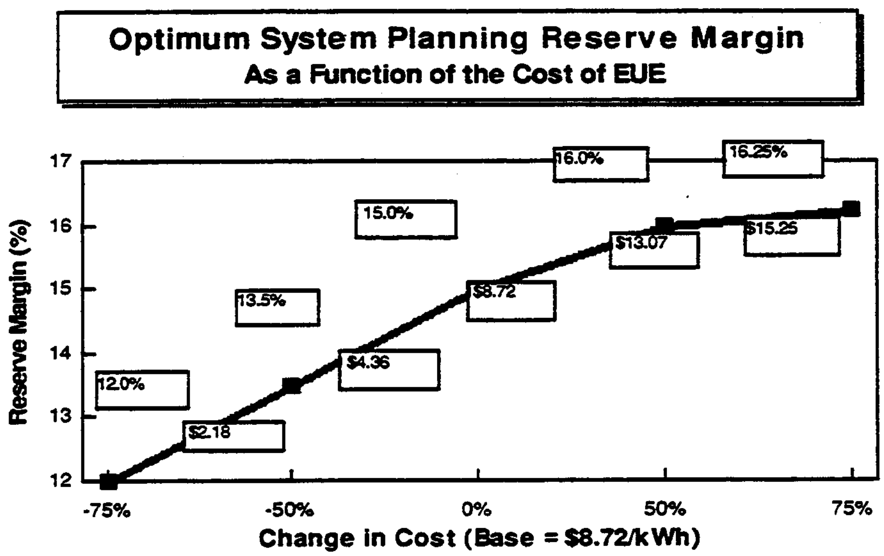


Exhibit IV.D2

E. Weather Variation

If there are no variations in weather, that is, if all years had the weather matching the average weather of the last 20-40 years, then fewer reserves would be needed. Exhibit IV.E1 shows the optimum system planning reserve margin would drop to around 8.0%.

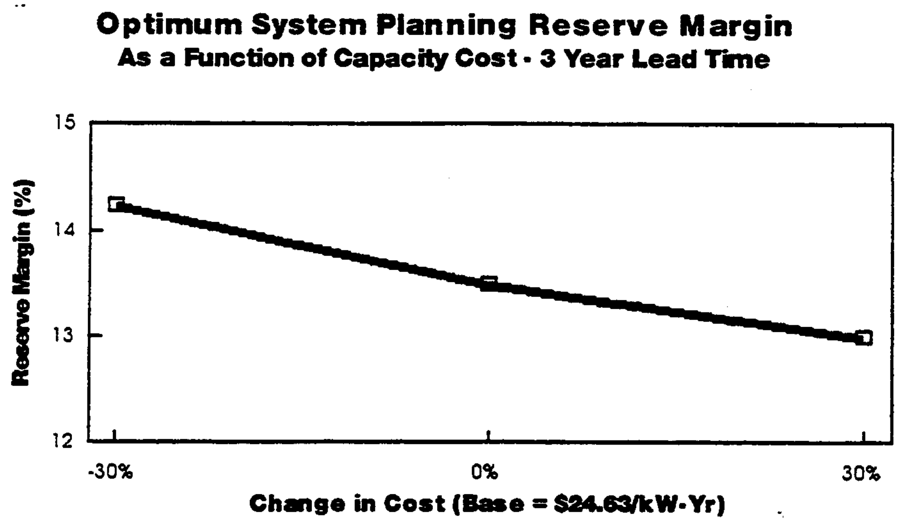


Exhibit IV.C1

D. Cost of Expected Unserved Energy

The base assumptions of the study uses an cost of EUE based on a weighted average cost of $4.34 per kilowatt-hour. While the reserve margin as a function of the cost of EUE was previously shown in Section III.A, Exhibit III.A1, the following table and graph (see Exhibits IV.D1 and IV.D2, respectively) illustrate how the margin would change if the cost of EUE was varied (decreased and increased). Based on the economics of developing such a margin, one would expect the margin to shift to the right (or increase) if the cost of EUE increases. For a cost of EUE of $2.18 per kilowatt- hour which is 50% less than the cost used, the optimum reserve margin would decrease to 12.0%. For an increase to approximately $15 per kilowatt-hour, the optimum margin would increase to the 16% range and began to level off. As stated in Section I.S of the report, this evaluation of system reserve margin requirements utilizes an update to the cost of EUE used in previous studies. By weighting customer outages more heavily to the residential customers, this value was reduced by approximately 50% from a value of $8.72 per kilowatt-hour (in 1996 dollars) to $4.34 per kilowatt-hour. To go to an even lower cost of EUE and still use the 1989/90 survey cost estimates, the contribution of the residential segment would have to be even higher. And vice-versa for a higher cost of EUE which would drive the margin upwards. This would require more weighting on the commercial and industrial segments that have a higher, associated cost of EUE than the residential customers, according to the survey results.

MW system, 1% reserves is about 320 MW which represents a capital cost savings of approximately $73 million (in 1996 dollars).

B. Unit Forced Outage Rates

The unit outage data is actual data for the previous five years with no adjustments. It encompasses the last five years of data for more than 100 thermal units, tapping a diverse database. Future revisits to this study will automatically incorporate improvement or degradation of unit performance. There appears to be no need to test changes in outage rates in the model now.

One conclusion that can be drawn from earlier results is that there is virtually no EUE from October to May; increasing unit availability during that period will have little reliability benefit. Alternately, it can be presumed that a one point reduction in the June-September forced outage rate of a 100 MW unit will increase effective system capacity by 1 MW.

C. CT Capacity Cost

Simple-cycle combustion turbine (CT) technology is used as the current measure of generating capacity cost in the economic evaluation of optimum reserve margins. However, the actual cost for a CT in the future may be more or less than the costs projected today. As an example, in the late 1990's and early 2000's, there is a possibility that increased emissions restrictions or some other factor could increase the cost. It is also possible that the improvements in materials or other factors could decrease the cost.

Exhibit IV.C1 is a graph of the target reserve margin as a function of the CT capacity cost. As shown, the target reserve margin will increase to 14.25% (from 13.5%) if the cost of a CT drops to 70% of the current projection. The margin decreases to 13.0% if the cost of a CT rises by 30%. This shows that that the margin is not overly sensitive to the capacity cost.

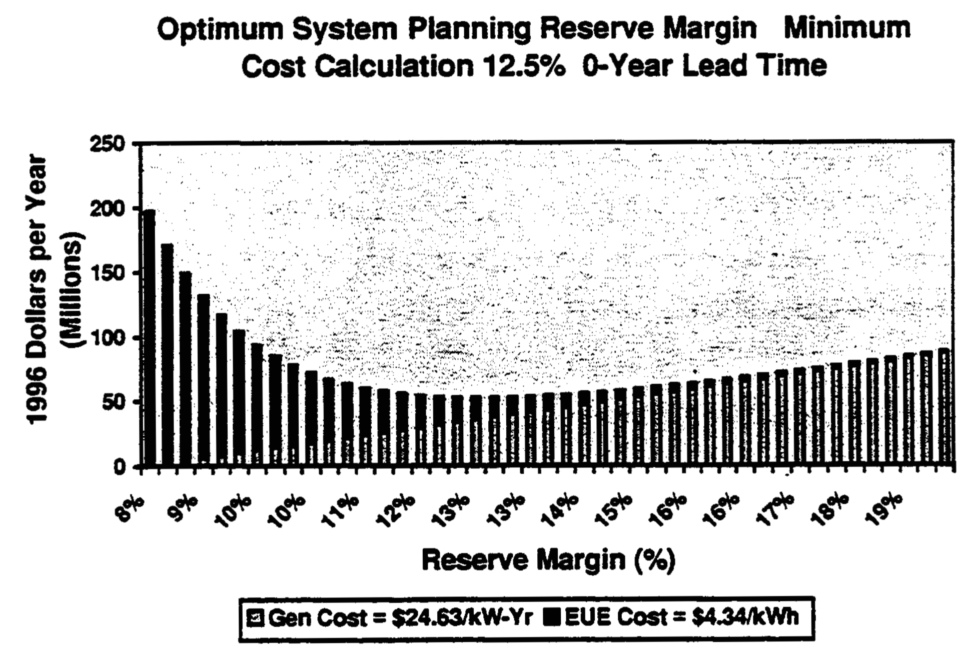
IV. SENSITIVITY RESULTS

A variety of alternate assumptions were evaluated to determine the sensitivity of the 13.5% target reserve margin. Some alternate assumptions require analytical work to evaluate; others become intuitively obvious after sufficient discussion. The sensitivities to cost of EUE and dispatch order were quantified earlier.

A. Load Forecast Uncertainty

The estimate of load forecast uncertainty in this study assumes the difference between the projection and the actual (weather-normalized) load for the summer three years into the future will have a triangular distribution around zero ranging from negative to positive 4%. As previously stated and shown in Section III.B of the report, if the load forecast could be projected with greater certainty, fewer reserves would be needed. If there were no (or "zero') load forecast uncertainty (i.e., perfect prophecy), Exhibit IV.A1 shows the target reserve margin would drop to about 12.5%. This is in line with Exhibit III.A3 which showed that load forecast uncertainty contributes approximately one percentage point to the target reserve margin.

Exhibit IV.A1



The value of a drop in the reserve margin from 13.5% to 12.5% (while holding system generation reliability constant) is the cost of maintaining the additional one percent reserves. For a 32,000 range of +/-2%. (Note, S[redacted]on IV of this report discusses ot[redacted]nsitivity type analysis centering around economic reserve margin calculations including an optimum reserve margin assuming "zero" load forecast uncertainty.) As shown in the exhibit, the optimum reserve margin for a 2-year lead-time is 13.25% while for a one-year out look, the margin is 12.75%.

Optimum System Planning Reserve Margin Minimum Cost Calculation 13.25% 2-Year Lead Time

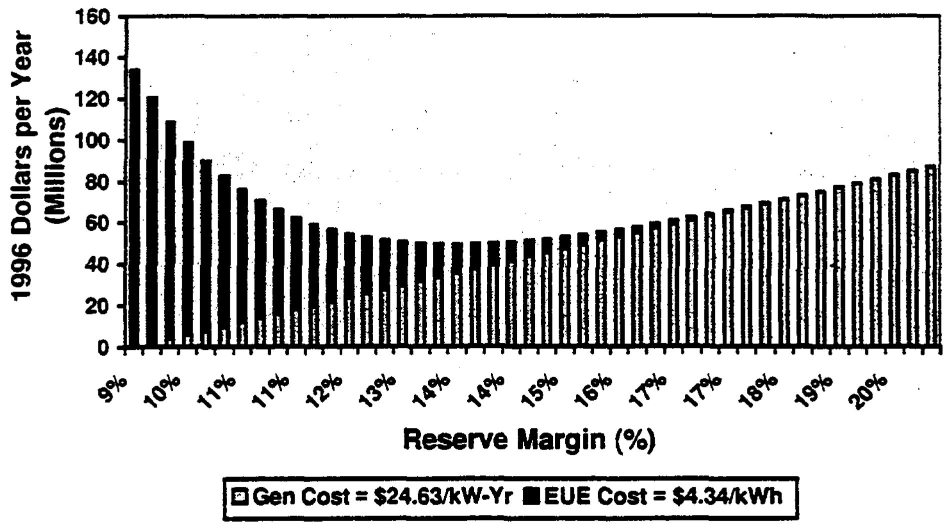


Exhibit III.B1

Optimum System Planning Reserve Margin Minimum Cost Calculation 12.75% 1-Year Lead Time

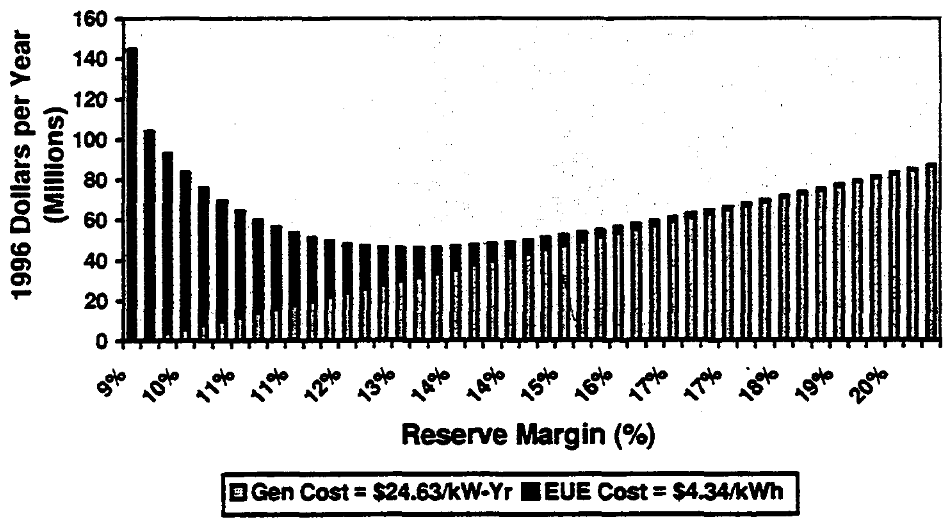


Exhibit III.B2

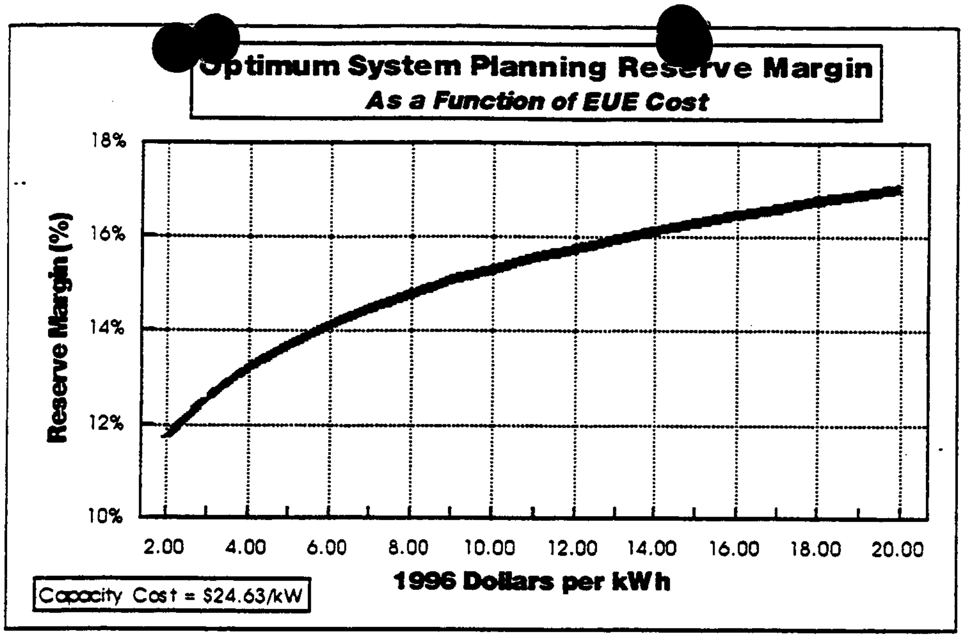


Exhibit III.A4

If reserves are significantly lower than the target of 13.5%, additional firm load curtailments may occur; customers would rather pay slightly higher bills and not suffer as many outages. If the reserves are significantly higher than the target then customers' bills may be too high due to the excess reserves and they would prefer slightly lower bills and slightly more risk of firm load curtailments.

The 13.5% minimum system planning reserve margin recommended for the system reflects the results of the economic study and a variety of other information available and is very important in planning to best meet customer needs. It will not be possible nor is it expected that the system will always stay at this target. The load forecast error alone could push the reserve margin higher or lower than the target.

B. Reserve Margins with Different Lead Times

Exhibits III.B1 and III.B2 display the optimum system planning reserve margins for 2-year and one-year lead times, respectively, using a fixed cost of EUE of $4.34 per kilowatt-hour and generating capacity cost of $24.63 per kilowatt-hour. The primary driver for these reduced reserve margins is the reduced load forecast uncertainty associated with more near-term planning. The assumption is made that for a one-year lead-time, load forecast uncertainty is appropriately represented by a range of +/-1%. Likewise, for a two-year out window or lead-time, load forecast uncertainty would be increased and is appropriately represented assuming a

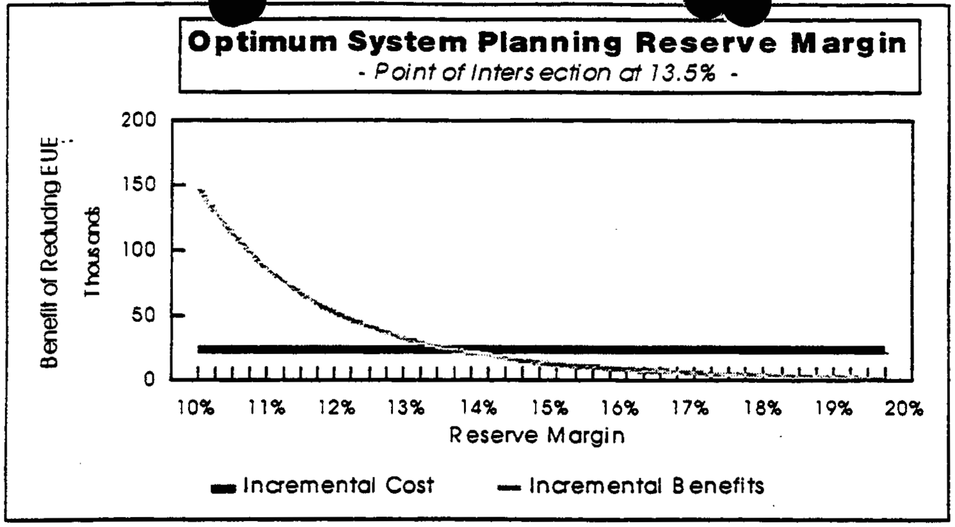


Exhibit III.A3

Of course, this type of study is only one piece of information which goes into the decision of the appropriate level of reserves as a planning target. Industry experience, system operations input, perceptions of risk, and an understanding of the strengths, weaknesses, and biases of mathematical models all influence capacity addition decisions. Also, the minimum "target reserve margin" is simply a convenient way to discuss the desired reliability, which might more technically be defined in loss of load hours or expected unserved energy. The optimum reserve margin for other levels of cost of EUE are shown Exhibit III.A4 and given by the equation:

$$y^{0.5} = a + bLN(x), \text{ where}$$
$$a = 0.3214$$
$$b = 0.0304$$
$$x = \text{Cost of EUE}$$

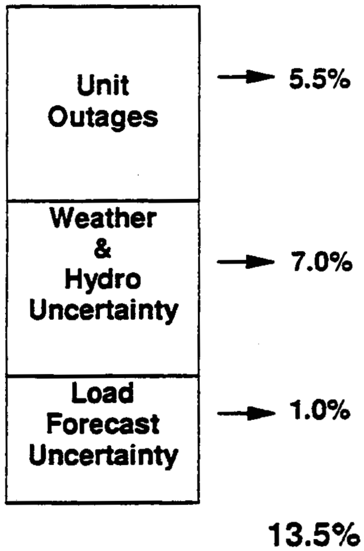


Exhibit III.A2

Another representation of the optimum reserve margin utilizes marginal cost and marginal benefit information instead of total cost. The incremental change in dollars per change in capacity (kW) is plotted for the societal benefits of reducing EUE and the capital costs of carrying additional reserves (capacity). The optimum reserve margin occurs where these two lines intersect, that is, the point at which the incremental cost is equal to the incremental benefit derived as shown in Exhibit III.A3. As an explanation of the exhibit, at a 10% reserve margin EUE is reduced by approximately 34 Megawatt-hours per 1 MW of generating capacity added. Thus the incremental benefit is equal to 34 Megawatt-hours times the cost of EUE ($4.34 per kilowatt-hour) or approximately $150,000 in 1996 dollars. As the reserve margin increases, the incremental benefit diminishes. At a 13.5% reserve margin, one MW of additional capacity only reduces EUE by about 6 Megawatt-hours resulting in an incremental benefit of approximately $26,000 per MW corresponding with the incremental cost of adding one MW of CT generating capacity.

A. Optimum System Planning Reserve Margin

Utilizing a $4.34 per kilowatt-hour cost of EUE, a generating capacity deferral cost of $24.63 per kilowatt-year, and the other assumptions listed above, **the optimum system planning minimum reserve margin for a three-year window (e.g., 1999) is 13.5% based on the economic, reliability analysis.** This conclusion is exemplified in Exhibit III.A1 in what is referred to as a "bathtub curve." The graph shows that at a 13.5% reserve margin, the sum of the two curves, the cost of capacity and cost of EUE curves, is at its minimum or optimal point.

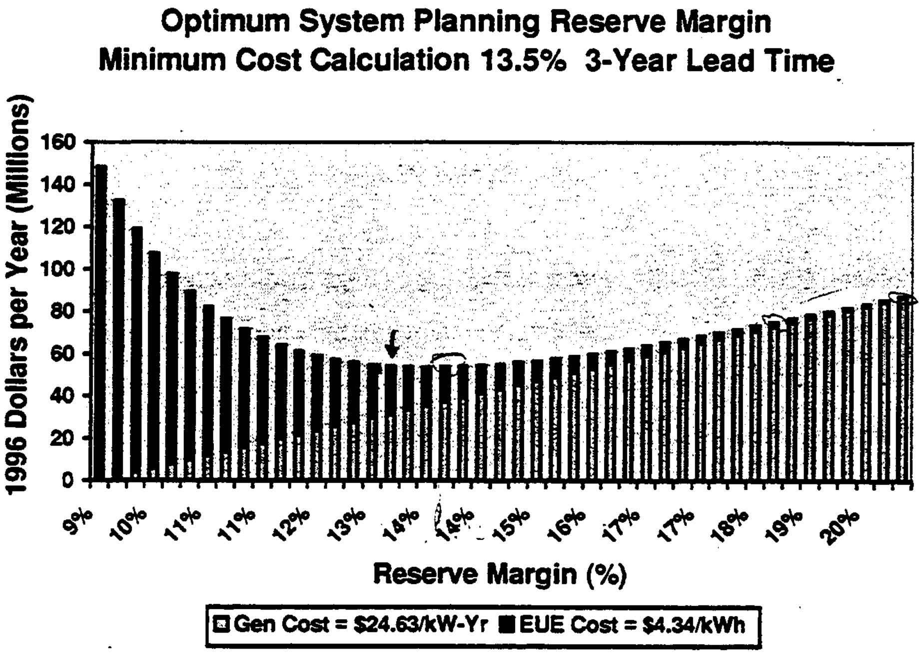


Exhibit III.A1

The total (outage and electricity) cost of being higher or lower than the optimum reserve margin is also shown in Exhibit III.A1. If reserves dropped three percentage points to 10.5%, the annual cost increase is about $29 million in 1996 dollars. If the margin increases to 16.5%, the cost increase is $10 million.

Exhibit III.A2 shows how each of the primary components: weather and hydro; unit performance; and, load-forecast uncertainty, contribute to the overall required system planning reserve margin.

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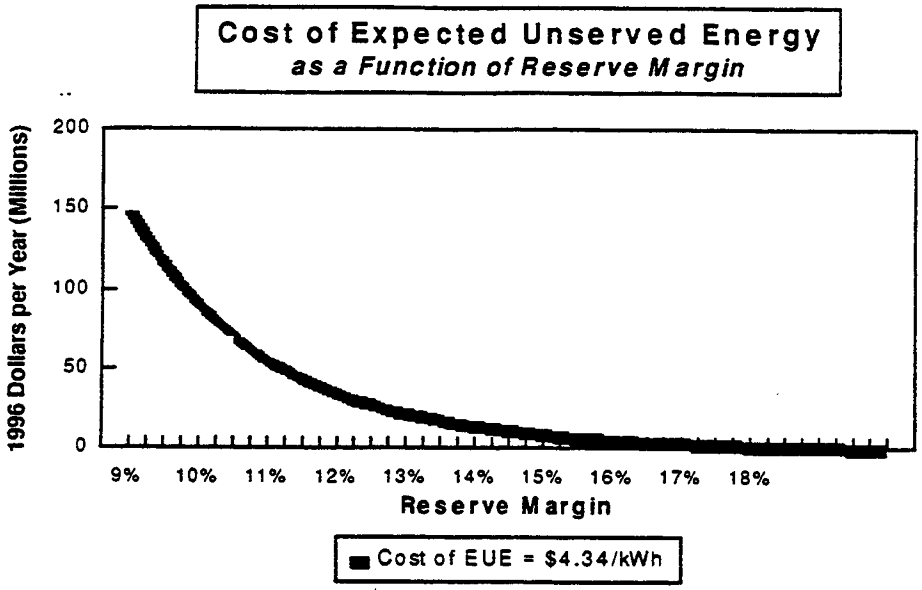

Exhibit II.D6

LOLH as a Function of Reserve Margin

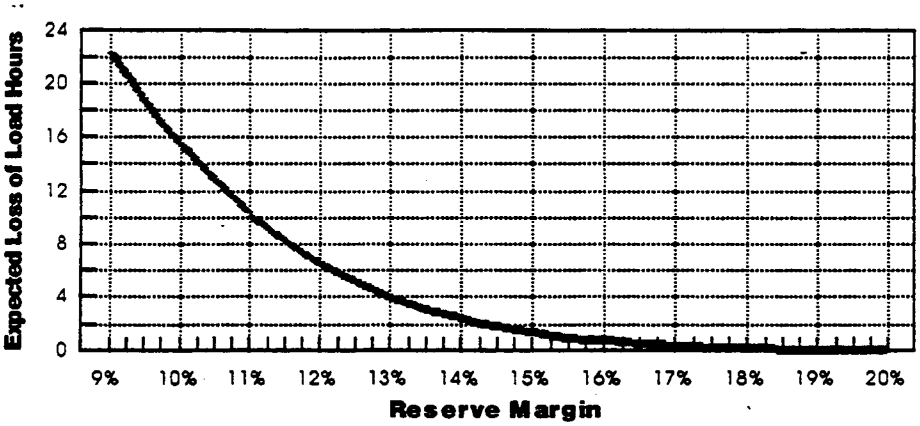

Exhibit II.D4

Generating Capacity Cost
as a Function of Reserve Margin

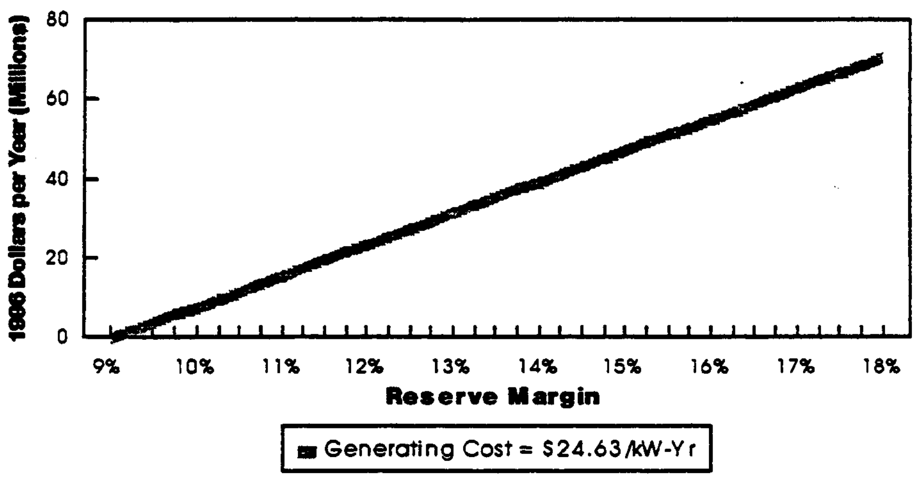

Exhibit II.D5

Likewise, an expected value of EUE and loss of load hours was calculated for all five reserve margin points (9%, 11%, 13%, 15%, & 17%). By applying regression analysis to the expected values, a curve predicting EUE and LOLH as a function of reserve margin can be developed as shown in Exhibits II.D3 and II.D4. The calculation of both components of annual reliability cost can now be accomplished. The incremental annual capacity carrying cost at any given reserve margin can be determined by multiplying the incremental capacity (kW) by $24.63/kW-year. This will be represented, as shown in Exhibit II.D5, by a straight line with a positive slope when graphed as a function of reserve margin. The cost of EUE at each reserve margin can be determined by multiplying the amounts of EUE at each reserve level created in the above mentioned regression analysis by the assumed cost of EUE. Exhibit II.D6 illustrates this calculation. The sum of these two curves is plotted on a graph. The minimum point on the resultant curve represents the economically optimum reserve margin. Examples of this type of graph, often referred to as a "bathtub curve," are presented in the Results section of the report.

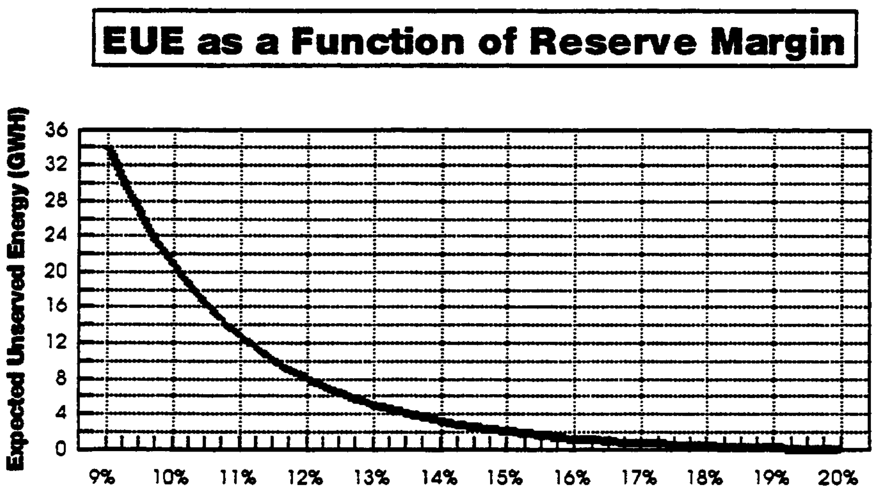

Exhibit II.D3

SOUTHERN COMPANY

Exhibit II.D2 - Calculation of Expected LOLH for June - Sept at 15% Reserve Margin Based on Model Results

(1) Weather Year	(2) Hydro Forecast	(3) Load Forecast Uncertainty	(4) LOLH	(5) Probability	(4 X 5) Weighted LOLH		(1) Weather Year	(2) Hydro Forecast	(3) Load Forecast Uncertainty	(4) LOLH	(5) Probability	(4 X 5) Weighted LOLH
1980	Dry	-2%	8.2	0.0017	0.01		1985	Wet	-2%	0.0	0.0183	0.00
		-4%	1.1	0.0003	0.00				-4%	0.0	0.0031	0.00
		0%	28.8	0.0031	0.09				0%	0.1	0.0336	0.00
		+2%	55.3	0.0017	0.09				+2%	0.7	0.0183	0.01
		+4%	90.3	0.0003	0.03				+4%	5.4	0.0031	0.02
1980	Normal	-2%	7.4	0.0033	0.02		1986	Dry	-2%	0.0	0.0167	0.00
		-4%	0.8	0.0006	0.00				-4%	0.0	0.0028	0.00
		0%	26.0	0.0061	0.16				0%	0.1	0.0305	0.00
		+2%	51.4	0.0033	0.17				+2%	0.4	0.0167	0.01
		+4%	84.6	0.0006	0.05				+4%	7.6	0.0028	0.02
1980	Wet	-2%	3.6	0.0017	0.01		1986	Normal	-2%	0.0	0.0333	0.00
		-4%	0.2	0.0003	0.00				-4%	0.0	0.0056	0.00
		0%	13.0	0.0031	0.04				0%	0.0	0.0611	0.00
		+2%	29.5	0.0017	0.05				+2%	0.3	0.0333	0.01
		+4%	60.8	0.0003	0.02				+4%	5.2	0.0056	0.03
1983	Dry	-2%	0.0	0.0183	0.00		1986	Wet	-2%	0.0	0.0167	0.00
		-4%	0.0	0.0031	0.00				-4%	0.0	0.0028	0.00
		0%	0.5	0.0336	0.02				0%	0.0	0.0305	0.00
		+2%	3.8	0.0183	0.07				+2%	0.4	0.0167	0.01
		+4%	13.6	0.0031	0.04				+4%	3.8	0.0028	0.01
1983	Normal	-2%	0.0	0.0367	0.00		1990	Dry	-2%	0.0	0.0033	0.00
		-4%	0.0	0.0061	0.00				-4%	0.0	0.0006	0.00
		0%	0.2	0.0672	0.01				0%	0.0	0.0061	0.00
		+2%	2.1	0.0367	0.08				+2%	0.3	0.0033	0.00
		+4%	9.5	0.0061	0.06				+4%	4.5	0.0006	0.00
1983	Wet	-2%	0.0	0.0183	0.00		1990	Normal	-2%	0.0	0.0067	0.00
		-4%	0.0	0.0031	0.00				-4%	0.0	0.0011	0.00
		0%	0.2	0.0336	0.01				0%	0.0	0.0122	0.00
		+2%	1.8	0.0183	0.03				+2%	0.1	0.0067	0.00
		+4%	7.0	0.0031	0.02				+4%	3.1	0.0011	0.00
1985	Dry	-2%	0.0	0.0183	0.00		1990	Wet	-2%	0.0	0.0033	0.00
		-4%	0.0	0.0031	0.00				-4%	0.0	0.0006	0.00
		0%	0.2	0.0336	0.01				0%	0.0	0.0061	0.00
		+2%	1.8	0.0183	0.03				+2%	0.1	0.0033	0.00
		+4%	8.2	0.0031	0.03				+4%	2.7	0.0006	0.00
1985	Normal	-2%	0.0	0.0367	0.00							
		-4%	0.0	0.0061	0.00							
		0%	0.0	0.0672	0.00							
		+2%	0.8	0.0367	0.03							
		+4%	5.5	0.0061	0.03							
								Sum of all Weighted LOLH = Expected LOLH				1.333

SOUTHERN COMPANY

Exhibit II.D1 - Calculation of Expected Unserved Energy (EUE in MWH) for June - Sept at 15% Reserve Margin Based on Model Results

(1) Weather Year	(2) Hydro Forecast	(3) Load Forecast Uncertainty	(4) EUE	(5) Probability	(4 X 5) Weighted EUE		(1) Weather Year	(2) Hydro Forecast	(3) Load Forecast Uncertainty	(4) EUE	(5) Probability	(4 X 5) Weighted EUE
1980	Dry	-2%	6869.3	0.0017	11.45		1985	Wet	-2%	0.0	0.0183	0.00
		-4%	712.8	0.0003	0.20				-4%	0.0	0.0031	0.00
		0%	34248.1	0.0031	104.59				0%	26.9	0.0336	0.90
		+2%	92284.2	0.0017	153.78				+2%	286.7	0.0183	5.26
		+4%	178109.7	0.0003	49.67				+4%	3645.8	0.0031	11.18
1980	Normal	-2%	5548.3	0.0033	18.49		1986	Dry	-2%	0.0	0.0167	0.00
		-4%	405.6	0.0006	0.23				-4%	0.0	0.0028	0.00
		0%	29399.5	0.0061	179.57				0%	12.5	0.0305	0.38
		+2%	83486.0	0.0033	278.24				+2%	159.2	0.0167	2.65
		+4%	164126.3	0.0006	91.53				+4%	5168.5	0.0028	14.41
1980	Wet	-2%	2014.8	0.0017	3.36		1986	Normal	-2%	0.0	0.0333	0.00
		-4%	71.6	0.0003	0.02				-4%	0.0	0.0056	0.00
		0%	11553.5	0.0031	35.28				0%	1.8	0.0611	0.11
		+2%	35055.3	0.0017	58.42				+2%	108.8	0.0333	3.62
		+4%	91708.2	0.0003	25.57				+4%	3100.8	0.0056	17.29
1983	Dry	-2%	1.3	0.0183	0.02		1986	Wet	-2%	0.0	0.0167	0.00
		-4%	0.0	0.0031	0.00				-4%	0.0	0.0028	0.00
		0%	304.2	0.0336	10.22				0%	4.6	0.0305	0.14
		+2%	2966.4	0.0183	54.38				+2%	137.7	0.0167	2.29
		+4%	15426.0	0.0031	47.32				+4%	2054.2	0.0028	5.73
1983	Normal	-2%	2.2	0.0367	0.08		1990	Dry	-2%	0.0	0.0033	0.00
		-4%	0.0	0.0061	0.00				-4%	0.0	0.0006	0.00
		0%	76.8	0.0672	5.16				0%	0.0	0.0061	0.00
		+2%	1325.6	0.0367	48.60				+2%	180.4	0.0033	0.60
		+4%	8434.1	0.0061	51.74				+4%	3886.7	0.0006	2.17
1983	Wet	-2%	1.9	0.0183	0.03		1990	Normal	-2%	0.0	0.0067	0.00
		-4%	0.0	0.0031	0.00				-4%	0.0	0.0011	0.00
		0%	83.5	0.0336	2.80				0%	0.3	0.0122	0.00
		+2%	909.4	0.0183	16.67				+2%	47.2	0.0067	0.31
		+4%	5493.1	0.0031	16.85				+4%	1977.5	0.0011	2.21
1985	Dry	-2%	0.0	0.0183	0.00		1990	Wet	-2%	0.0	0.0033	0.00
		-4%	0.1	0.0031	0.00				-4%	0.0	0.0006	0.00
		0%	105.6	0.0336	3.55				0%	0.0	0.0061	0.00
		+2%	1228.5	0.0183	22.52				+2%	49.1	0.0033	0.16
		+4%	7861.9	0.0031	24.12				+4%	1649.0	0.0006	0.92
1985	Normal	-2%	2.2	0.0367	0.08							
		-4%	0.0	0.0061	0.00							
		0%	12.3	0.0672	0.83							
		+2%	380.4	0.0367	13.95							
		+4%	3700.7	0.0061	22.70							
								Sum of all Weighted EUE = Likely EUE				1422.3

SOUTHERN COMPANY

Weather Years	Hydro Outlook	Load Forecast Uncertainty
1963	Normal	+4.0%
1982		+2.0%
1984		0.0%
1985		-2.0%
		-4.0%

Total # of cases = 4 * 1 * 5 = 20

Note, historically during the winter season the availability of hydro energy is not a concern thus only the normal hydro scenario is modeled in the winter analysis.

For each of the 95 cases (75 for summer and 20 for winter), each hour in the month was modeled with 100 iterative draws from the distribution of generating unit outage and duration data to determine if there exists a deficiency of generating capacity to meet load demand. A deficiency of generating capacity in a given hour is recorded as a loss of load hour. The magnitude of the outage during that hour can be described by EUE. Based upon the model simulations, an average LOLH and EUE are determined for each case across all hours in the month. Then, the average LOLH and EUE in each case are multiplied by the probability of occurrence for that case and the result for all cases is summed to determine an expected value of LOLH and EUE for the study year.

Exhibits II.D1 and II.D2 illustrates an example of likely EUE and expected loss of load hour calculations, respectively, for the study year, the summer season, and one reserve margin (15%) based on modeling results:

$$\textbf{Expected Y} = \sum_{i=1}^{75} \underbrace{(Y_i}_{\text{(column 4)}} \times \underbrace{\text{Probability}_i)}_{\text{(column 5)}}$$

where, Y = EUE or LOLH and, i = number of cases

D. Reliability Model Simulations

Generation reliability simulations are conducted using a model that incorporates Monte Carlo techniques. Monte Carlo analysis uses a random number generator to determine generating unit availability for the system. For each iteration, the model simulations will randomly select the state of a generating unit as fully operational, partially failed or completely failed and determine if the system experiences loss of load and associated EUE. Historical information concerning load-forecast uncertainty, weather, and hydro energy is used to construct numerous cases that could occur for a future year.

For a single reserve margin, a set of 75 cases was developed using the following table of weather, hydro, and load forecast uncertainty combinations to represent the summer season:

Weather Years	Hydro Outlook	Load Forecast Uncertainty
1980	Dry	+4.0%
1983	Normal	+2.0%
1985	Wet	0.0%
1986		-2.0%
1990		-4.0%

Total # of cases = 5 * 3 * 5 = 75

Likewise, for a single reserve margin a set of 20 cases was developed using the following table of weather, hydro, and load forecast uncertainty combinations to represent the winter season:

Using probabilistic evaluation techniques requires each of these variables to have a designated probability of occurrence. Exhibit II.C1 depicts the probabilities assigned to each weather year, each hydro pattern, and each load forecast uncertainty. A total probability associated with a combination of these three variables can be calculated using the three associated probabilities. The probabilities for both the summer and winter analyses are included.

Probabilities Assigned to Various Input Variables						
	Weather Year	**Probability**	**Hydro Pattern**	**Probability**	**LFE**	**Probability**
Summer	1980	0.0278	Dry	0.25	+4%	0.0401
	1983	0.2778	Normal	0.50	+2%	0.2400
	1986	0.1667	Wet	0.25	0%	0.4398
	1990	0.0833			-2%	0.2400
	1985	0.1111			-4%	0.0401
Winter	1963	0.1667	Normal	1.00	+4%	0.0401
	1982	0.1667			+2%	0.2400
	1984	0.1389			0%	0.4398
	1985	0.1944			-2%	0.2400
					-4%	0.0401

Exhibit II.C1

As shown, the probabilities assigned for the weather years for each season, summer and winter, do not sum to 1.0 or 100%. As previously mentioned, the model simulations were made for those weather years which were projected to yield periods of EUE and LOLH. However, equal probability is given (on a year-by-year basis) to those years that did not project to have generation reliability problems. These years make up the difference, in probability, between the probability shown for the above years and an expected total of 1.0.

B. PEST Case Specification

The hourly EUE profiles from the set of 95 cases were each subjected to tie assistance evaluation, assuming the system had equal access to ETA with other neighboring utilities.

PEST was also used to test the availability of the input economy purchases. An initial set of runs was made to test the assumptions of economy purchase availability. A strict application of PEST reveals there may be some hours in which more economy purchases are assumed to be available in the input data than can be shown to be available from MCFRED outputs. There are three reasons:

1) Minimum flow hydro energy, which was excluded from earlier calculations, could be considered a source of additional economy ties;

2) Transmission constraints used in calculating ETA and in the PEST validity test are based on first contingency transfer limits. That is, they assume a major transmission line is already out-of-service; and,

3) During the morning and late evening hours, when the economy ties are assumed to be available, there is more transmission capacity and more generating capacity (due to the lower ambient temperatures) than are reflected in MCFRED. (For example, the maximum electrical output of CTs increases when the temperature drops from 95 to 88 degrees and there are several thousand MWs of CT capacity in the Southeast.

C. Probabilities of Occurrence for Input Variables

As has been discussed in the previous sections, the chronological variable inputs into the model, excluding the unit outage data, are used to represent appropriate ranges of data. For example, the weather years selected to exemplify load variations due to temperature changes represent over 30 years of historical data. Likewise for the hydro patterns developed. The low, likely, and high hydro scenarios are representative of the variation of hydro availability. And finally, the implementation of load forecast uncertainty into the evaluation is representative of the potential (supported by historical information) load forecasting problems when looking out into the future.

Exhibit II.A3

Annual Loss of Load Hours (LOLH) for Various Reserve Levels with Tie Assistance

- Assumes 0% Load Forecast Uncertainty -

	Weather Year	Hydro Pattern	9% Reserves LOLH	11% Reserves LOLH	13% Reserves LOLH	15% Reserves LOLH	17% Reserves LOLH
Summer	**1980**	**Dry**	144.53	81.17	52.16	28.80	13.74
		Normal	133.63	74.45	49.30	26.02	13.31
		Wet	93.50	51.86	30.70	12.96	6.08
	1983	**Dry**	33.72	16.66	5.70	0.48	0.03
		Normal	26.41	11.33	3.65	0.21	0.02
		Wet	18.29	8.47	2.99	0.18	0.01
	1985	**Dry**	32.15	9.15	2.14	0.18	0.02
		Normal	24.88	5.66	1.04	0.06	0.01
		Wet	17.51	4.03	0.81	0.03	0.00
	1986	**Dry**	30.91	7.35	1.04	0.05	0.00
		Normal	23.16	4.32	0.82	0.03	0.00
		Wet	15.86	3.52	0.70	0.02	0.00
	1990	**Dry**	13.13	2.47	0.17	0.00	0.00
		Normal	8.54	1.43	0.11	0.00	0.00
		Wet	7.55	1.12	0.09	0.00	0.00
Winter	**1985**	**Normal**	2.67	1.66	1.25	0.10	0.10
	1963	**Normal**	0.03	0.01	0.00	0.00	0.00
	1983	**Normal**	0.01	0.00	0.00	0.00	0.00
	1984	**Normal**	0.00	0.00	0.00	0.00	0.00

Exhibit II.A2

Annual MWHs of EUE for Various Reserve Levels with Tie Assistance

- Assumes 0% Load Forecast Uncertainty -

	Weather Year	Hydro Pattern	9% Reserves EUE	11% Reserves EUE	13% Reserves EUE	15% Reserves EUE	17% Reserves EUE
Summer	**1980**	**Dry**	314,435.3	155,760.4	89,909.4	34,248.1	13,137.4
		Normal	283,667.8	142,455.0	83,033.1	29,399.5	12,206.9
		Wet	173,092.7	81,659.1	38,889.4	11,553.5	3,977.1
	1983	**Dry**	52,931.7	20,935.5	4,939.2	304.2	17.3
		Normal	34,478.6	11,226.7	2,473.4	152.3	8.7
		Wet	21,337.6	7,012.0	1,865.7	83.5	4.8
	1985	**Dry**	41,324.3	7,264.6	1,713.9	105.6	6.0
		Normal	26,378.4	2,987.0	436.7	26.9	1.5
		Wet	14,691.8	2,165.3	387.5	12.3	0.7
	1986	**Dry**	34,131.4	5,060.0	499.1	12.5	4.2
		Normal	20,882.9	2,334.1	292.0	1.8	0.6
		Wet	12,936.2	1,927.3	291.2	4.6	0.1
	1990	**Dry**	13,196.7	1,820.4	67.3	1.0	0.0
		Normal	6,188.1	800.7	36.9	0.3	0.0
		Wet	5,088.6	542.2	31.1	0.0	0.0
Winter	**1985**	**Normal**	2,886.6	1,201.7	834.9	39.3	36.8
	1963	**Normal**	8.7	2.3	0.0	0.0	0.0
	1983	**Normal**	3.3	0.0	0.0	0.0	0.0
	1984	**Normal**	0.0	0.0	0.0	0.0	0.0

Prior to introduction of load forecast uncertainty, the total number of combinations for the summer analysis is five times three times five, or 75 cases. For the winter analysis, the case representation prior to introducing load forecast uncertainty into the equation, is four times one time five, or 20 cases. (Notes: (1) Hydro was proven not to be a "player" in the non-summer months thus only the "normal" hydro scenario or pattern was used in the winter analysis. (2) Furthermore, it is also assumed that the spring and fall seasons are not yet critical in determining system reserve margin requirements thus are not included in this reliability evaluation.) Estimating EUE for each of the 95 cases through a rigorous application of MCFRED and PEST provides sufficient data for regression analysis of other combinations not specifically calculated in the detailed models.

Only results for normal and hotter-than-normal weather and underestimation of load were specifically calculated. This does not imply that the EUE is therefore overestimated. In each case, the likelihood of cool summers and warm winters and subsequently overestimated loads is given equal weighting with the likelihood of hot summers and cold winters and subsequently underestimated loads. Seeking more accuracy in the higher EUE cases increases the accuracy of all the final results by providing better estimates of the situations that have the greatest impact on the final results. (In practice, no model is needed to estimate the EUE for highly reliable situations such as 21% planned reserves and -4.0% load forecast error; the EUE rounds to zero.)

Exhibits II.A2 and II.A3, respectively, lists the EUE and LOLH, without inclusion of load forecast uncertainty, for the 95 cases after emergency tie assistance (ETA) is applied. From the exhibit, for example, at 13% reserves, 1983 (very hot) weather, dry hydro pattern and no load forecast error the expected unserved energy is about 5,000 Megawatt-hours. This could be interpreted as dropping 5,000 MWs of load for one hour, 2,500 MWs of load for two hours, or some other combination that equals 5,000 Megawatt-hours. Also for the same scenario, the expected or likely annual loss of load hours, of which the majority is in the summer months, is approximately six (6) hours.

II. SIMULATION PROCEDURE

A. MCFRED Case Specification

The simulations were designed to estimate system generation reliability across a range of weather conditions, load forecast errors, and reserve margins. To increase confidence in the regression analyses used to interpolate and extrapolate results, the reserve margin variables were set to five discrete points. The weather variable was set to cover both the summer and winter seasons and over 30 years of weather data was represented by five points (summer) and four points (winter). The hydro patterns were set at three points for the summer and one point for the winter analysis.

Specific weather years -- 1980, 1990, 1986, 1985, and 1983 -- were selected for the summer reliability analysis. These years are significant in terms of observed weather patterns as confirmed by an evaluation of annual peaks and energies and the cooling degree day calculations with specific reference temperatures of 72 and 92 degrees F, for thirty-one years of historical weather data. When this data was normalized, the results yielded the selection of the five specific weathers above with 1980 being the hottest. Likewise for the winter reliability analysis, four colder than normal weather years -- 1963, 1982, 1984, and 1985 -- were selected to represent those conditions that could produce EUE and LOLH during the winter months.

Thus the simulation variables were as depicted in Exhibit II.A1:

Exhibit II.A1 - MCFRED Case Variables

Summer Weather Years	*Winter Weather Years*	*Hydro Patterns*	*Reserve Margins*
1980	1963	Wet	9.0%
1983	1982	Normal	11.0%
1986	1984	Dry	13.0%
1990	1985		15.0%
1985			17.0%

weighting of the customer classes. But as also stated in the report, future studies may give consideration to weighing the residential cost of EUE more heavily into the calculation. After surveying various operating companies' divisions as to what percentages each customer segment contributes to a generic block of load that would be shed in such times of need, the cost of EUE was adjusted by the weight each customer class would contribute in such a load shed scenario. The cost of EUE (in 1996 dollars) using the original weightings is estimated at $8.72 per kilowatt-hour. By using increased weighting on the residential segment, the cost of EUE is estimated at $4.34 per kilowatt-hour. This is the cost of EUE that will be used in this study.

1. Provide a 20-year, present worth revenue requirements (PWRR) analysis of Gulf's proposed Smith Unit 3, the other self-build options, and all respondents to Gulf's Request for Proposals (RFP). Provide both on an annual and a cumulative PWRR basis, and separate capital, fixed operations and maintenance (O&M), and variable costs for each year. Include all financial assumptions for the self-build options and the respondents.

RESPONSE:

The values requested for the four self-build analysis options are attached. The financial assumptions used for the Self-build analysis are those shown for 1997 in the answer to Interrogatory No. 13. The response for the figures pertaining to the RFP analyses have been filed with a Letter of Intent to request Confidential treatment.

Attachment 1-1
Staffs 1st set of Interrogatories - No. 1
Docket No. 990325-EI

TABULATION OF ANNUAL AND CUMULATIVE PRESENT VALUE COST DATA FOR SMITH CC SELF-BUILD OPTION

	Nominal $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	20,528	780	19,273	23,712	16,869
2002	33,226	1,377	35,916	44,891	25,629
2003	31,798	1,420	36,883	47,084	23,016
2004	30,445	1,463	37,042	48,673	20,277
2005	29,135	1,508	35,907	46,651	19,898
2006	27,865	1,554	32,465	42,758	19,126
2007	26,631	1,602	30,158	40,216	18,174
2008	25,432	1,651	28,424	38,433	17,074
2009	24,253	1,701	30,804	41,599	15,159
2010	23,077	1,753	33,343	45,135	13,038
2011	21,902	1,807	34,551	46,944	11,316
2012	20,729	1,862	35,827	48,962	9,457
2013	19,557	1,919	37,362	51,199	7,640
2014	18,387	1,978	38,816	53,314	5,867
2015	17,217	2,039	40,067	55,291	4,033
2016	16,050	2,101	41,394	57,431	2,113
2017	14,883	2,166	40,589	55,473	2,164
2018	13,718	2,232	38,535	52,099	2,386
2019	12,555	2,300	36,713	49,106	2,462
2020	11,393	2,371	37,782	50,448	1,098
2021	4,416	1,018	15,965	21,309	89

	Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	15,239	559	13,820	17,003	12,616
2002	22,698	909	23,699	29,621	17,685
2003	19,989	862	22,396	28,590	14,657
2004	17,612	818	20,698	27,197	11,930
2005	15,509	775	18,463	23,988	10,760
2006	13,650	735	15,361	20,232	9,515
2007	12,005	697	13,131	17,511	8,322
2008	10,550	661	11,389	15,399	7,201
2009	9,258	627	11,358	15,338	5,905
2010	8,106	595	11,313	15,314	4,700
2011	7,080	564	10,788	14,657	3,774
2012	6,166	535	10,294	14,067	2,927
2013	5,353	507	9,878	13,536	2,202
2014	4,631	481	9,444	12,971	1,585
2015	3,991	456	8,971	12,379	1,039
2016	3,423	433	8,528	11,832	552
2017	2,921	411	7,695	10,517	510
2018	2,478	389	6,723	9,089	501
2019	2,087	369	5,894	7,884	466
2020	1,742	350	5,582	7,453	222
2021	621	138	2,170	2,897	33

	Accumulated Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	15,239	559	13,820	17,003	12,616
2002	37,937	1,468	37,520	46,624	30,301
2003	57,927	2,330	59,915	75,215	44,958
2004	75,539	3,148	80,613	102,412	56,888
2005	91,048	3,923	99,076	126,399	67,648
2006	104,698	4,658	114,437	146,631	77,163
2007	116,703	5,356	127,569	164,142	85,485
2008	127,252	6,017	138,957	179,541	92,686
2009	136,510	6,644	150,315	194,879	98,590
2010	144,616	7,239	161,628	210,193	103,290
2011	151,695	7,804	172,416	224,850	107,065
2012	157,861	8,339	182,709	238,917	109,992
2013	163,214	8,846	192,587	252,453	112,195
2014	167,846	9,327	202,031	265,424	113,780
2015	171,836	9,784	211,002	277,803	114,819
2016	175,260	10,217	219,530	289,635	115,371
2017	178,181	10,627	227,225	300,152	115,881
2018	180,658	11,017	233,948	309,241	116,381
2019	182,745	11,386	239,842	317,125	116,848
2020	184,488	11,736	245,423	324,578	117,069
2021	185,109	11,875	247,594	327,475	117,103

TABULATION OF ANNUAL AND CUMULATIVE PRESENT VALUE COST DATA FOR SMITH CT SELF-BUILD OPTION

	Nominal $1,000					Present Worth 1998 $1,000					Accumulated Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	16,348	673	0	0	17,020	12,136	482	0	0	12,618	12,136	482	0	0	12,618
2002	26,041	1,188	0	0	27,229	17,790	784	0	0	18,574	29,926	1,267	0	0	31,192
2003	24,886	1,225	0	0	26,110	15,644	744	0	0	16,388	45,570	2,010	0	0	47,580
2004	23,905	1,262	0	0	25,167	13,828	705	0	0	14,534	59,398	2,716	0	0	62,114
2005	22,957	1,301	0	0	24,258	12,221	669	0	0	12,890	71,619	3,385	0	0	75,003
2006	22,041	1,341	0	0	23,382	10,797	634	0	0	11,431	82,416	4,019	0	0	86,435
2007	21,153	1,382	0	0	22,535	9,535	602	0	0	10,137	91,951	4,621	0	0	96,572
2008	20,293	1,424	0	0	21,717	8,418	571	0	0	8,988	100,369	5,191	0	0	105,560
2009	19,449	1,468	0	0	20,917	7,424	541	0	0	7,965	107,793	5,732	0	0	113,525
2010	18,609	1,513	0	0	20,121	6,536	513	0	0	7,050	114,330	6,246	0	0	120,575
2011	17,770	1,559	549	551	19,328	5,744	487	172	172	6,230	120,074	6,732	172	172	126,806
2012	16,935	1,607	579	605	18,516	5,037	462	166	174	5,491	125,111	7,194	338	346	132,297
2013	16,101	1,656	602	623	17,736	4,407	438	159	165	4,839	129,518	7,632	497	511	137,136
2014	15,270	1,707	626	643	16,960	3,846	415	152	156	4,257	133,364	8,047	650	667	141,394
2015	14,441	1,759	661	662	16,198	3,347	394	148	148	3,741	136,711	8,441	797	815	145,134
2016	13,614	1,813	0	0	15,427	2,904	373	0	0	3,277	139,615	8,814	797	815	148,412
2017	12,790	1,868	0	0	14,659	2,510	354	0	0	2,865	142,125	9,169	797	815	151,276
2018	11,969	1,926	0	0	13,895	2,162	336	0	0	2,498	144,287	9,505	797	815	153,774
2019	11,151	1,984	0	0	13,135	1,853	319	0	0	2,172	146,140	9,823	797	815	155,946
2020	10,335	2,045	0	0	12,380	1,581	302	0	0	1,883	147,721	10,125	797	815	157,829
2021	4,081	878	0	0	4,960	574	119	0	0	694	148,296	10,245	797	815	158,523

TABULATION OF ANNUAL AND CUMULATIVE PRESENT VALUE COST DATA FOR DANIEL CC SELF-BUILD OPTION

	Nominal $1,000					Present Worth 1998 $1,000					Accumulated Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	36,048	324	20,004	25,716	30,661	26,761	233	14,344	18,440	22,898	26,761	233	14,344	18,440	22,898
2002	56,095	573	34,481	45,696	45,453	38,321	378	22,753	30,153	31,298	65,082	611	37,097	48,593	54,196
2003	53,885	591	34,620	47,084	42,011	33,874	359	21,022	28,590	26,664	98,955	970	58,118	77,183	80,860
2004	51,914	609	34,763	48,673	38,612	30,031	340	19,424	27,197	22,598	128,987	1,310	77,543	104,380	103,459
2005	50,013	627	37,345	50,306	37,680	26,624	323	19,202	25,867	20,282	155,610	1,632	96,745	130,247	123,740
2006	48,179	647	35,061	47,706	36,182	23,601	306	16,590	22,573	17,924	179,211	1,938	113,335	152,820	141,665
2007	46,407	667	31,733	43,998	34,809	20,919	290	13,817	19,158	15,869	200,131	2,229	127,152	171,977	157,534
2008	44,693	687	29,567	41,734	33,213	18,539	275	11,847	16,722	13,940	218,670	2,504	138,999	188,699	171,473
2009	43,014	708	32,197	45,214	30,706	16,419	261	11,871	16,671	11,881	235,089	2,765	150,870	205,370	183,354
2010	41,346	730	33,921	47,908	28,090	14,523	248	11,509	16,255	10,026	249,613	3,012	162,380	221,625	193,380
2011	39,685	752	34,937	49,556	25,819	12,828	235	10,908	15,472	8,498	262,440	3,247	173,288	237,097	201,878
2012	38,031	775	35,806	51,186	23,426	11,312	223	10,288	14,707	7,116	273,753	3,470	183,575	251,804	208,994
2013	36,384	799	37,246	53,338	21,090	9,959	211	9,847	14,102	5,915	283,712	3,681	193,423	265,906	214,910
2014	34,745	823	38,468	55,279	18,757	8,751	200	9,359	13,449	4,862	292,463	3,881	202,782	279,355	219,771
2015	33,113	848	40,279	57,869	16,371	7,675	190	9,018	12,956	3,927	300,138	4,071	211,800	292,311	223,698
2016	31,489	874	41,708	60,096	13,975	6,716	180	8,593	12,381	3,108	306,854	4,251	220,393	304,692	226,806
2017	29,873	901	41,330	58,560	13,544	5,863	171	7,836	11,102	2,768	312,718	4,422	228,228	315,794	229,574
2018	28,266	929	38,712	54,552	13,354	5,105	162	6,754	9,517	2,504	317,823	4,584	234,982	325,311	232,078
2019	26,667	957	37,764	52,409	12,980	4,432	154	6,063	8,414	2,235	322,255	4,738	241,045	333,725	234,313
2020	25,078	986	38,595	53,543	11,117	3,836	146	5,702	7,910	1,773	326,091	4,884	246,746	341,635	236,086
2021	10,027	424	16,510	22,861	4,099	1,411	58	2,244	3,108	605	327,502	4,941	248,991	344,743	236,691

Attachment 1-4
Staffs 1st set of Interrogatories - No. 1
Docket No. 990325-EI

TABULATION OF ANNUAL AND CUMULATIVE PRESENT VALUE COST DATA FOR MULAT TOWER COGEN SELF-BUILD OPTION

	Nominal $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	28,867	5,180	20,851	25,750	29,148
2002	44,679	8,904	35,856	45,696	43,743
2003	42,940	8,928	35,969	47,084	40,753
2004	41,404	8,953	36,086	48,673	37,770
2005	39,925	8,979	38,602	50,306	37,199
2006	38,498	9,006	40,713	52,102	36,115
2007	37,121	9,033	39,869	51,054	34,968
2008	35,790	9,061	36,347	47,235	33,964
2009	34,488	9,090	39,099	50,984	31,693
2010	33,194	9,120	40,850	53,738	29,427
2011	31,907	9,151	41,653	55,165	27,546
2012	30,626	9,183	42,595	56,877	25,527
2013	29,351	9,215	44,385	59,420	23,531
2014	28,082	9,249	45,806	61,609	21,528
2015	26,821	9,284	47,036	63,651	19,490
2016	25,566	9,320	48,734	66,194	17,425
2017	24,319	9,357	46,469	62,784	17,360
2018	23,078	9,395	45,456	60,527	17,403
2019	21,846	9,434	43,676	57,347	17,609
2020	20,621	9,474	43,920	57,842	16,174
2021	8,271	3,965	18,876	24,826	6,287

	Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	21,430	3,715	14,952	18,465	21,632
2002	30,522	5,875	23,660	30,153	29,904
2003	26,994	5,421	21,841	28,590	25,666
2004	23,952	5,003	20,164	27,197	21,921
2005	21,253	4,617	19,849	25,867	19,852
2006	18,859	4,261	19,264	24,653	17,731
2007	16,733	3,933	17,359	22,230	15,796
2008	14,846	3,631	14,563	18,926	14,114
2009	13,165	3,352	14,416	18,798	12,134
2010	11,660	3,094	13,860	18,233	10,382
2011	10,314	2,857	13,005	17,224	8,952
2012	9,110	2,638	12,238	16,341	7,645
2013	8,034	2,436	11,735	15,710	6,495
2014	7,073	2,250	11,144	14,989	5,479
2015	6,217	2,079	10,531	14,251	4,575
2016	5,453	1,920	10,040	13,638	3,776
2017	4,773	1,774	8,810	11,903	3,454
2018	4,168	1,639	7,930	10,560	3,178
2019	3,631	1,515	7,012	9,207	2,951
2020	3,154	1,400	6,488	8,545	2,497
2021	1,164	539	2,566	3,375	894

	Accumulated Present Worth 1998 $1,000				
Year	Capital	Fixed O&M	Fuel + VO&M	Fuel Savings	Total
2001	21,430	3,715	14,952	18,465	21,632
2002	51,952	9,590	38,612	48,618	51,536
2003	78,945	15,012	60,452	77,208	77,202
2004	102,897	20,014	80,616	104,405	99,123
2005	124,150	24,631	100,465	130,272	118,974
2006	143,009	28,892	119,729	154,925	136,705
2007	159,742	32,825	137,088	177,154	152,501
2008	174,588	36,456	151,652	196,080	166,615
2009	187,753	39,808	166,068	214,879	178,750
2010	199,413	42,902	179,928	233,111	189,131
2011	209,726	45,759	192,933	250,335	198,083
2012	218,836	48,397	205,171	266,677	205,728
2013	226,869	50,834	216,906	282,387	212,223
2014	233,943	53,084	228,051	297,376	217,702
2015	240,159	55,163	238,581	311,627	222,277
2016	245,613	57,083	248,622	325,264	226,053
2017	250,386	58,857	257,431	337,167	229,506
2018	254,554	60,496	265,362	347,727	232,685
2019	258,185	62,010	272,374	356,933	235,635
2020	261,339	63,410	278,862	365,478	238,132
2021	262,503	63,949	281,428	368,853	239,027

FPSC Staff's First Set
Of Interrogatories
Docket No. 990325-EI
GULF POWER COMPANY
April 19, 1999
Item No. 2

2. Provide a side-by side comparison of Gulf's base case generation expansion plan, the expansion plans resulting from the other self-build options, and the expansion plans resulting from each RFP respondent's project. If the RFP respondent's proposal is for less than twenty years, include the type and timing of the resources added by Gulf to meet is reliability criteria in later years of the plan. For all expansion plan cases, give the resulting annual summer and winter reserve margin on Gulf's system.

RESPONSE:

There was no remix of capacity resources in the original self-build evaluation process. For both the self-build and the RFP evaluation process, an allocated Southern expansion plan (specifically for Gulf Power) was not created in the evaluation of each of these supply side resources. Correspondingly, no operating company reserve margin information is available for each of these cases. However, the expansion plan information from each alternative PROVIEW® case in the RFP evaluation has been compiled and is attached.

Cummulative Expansion Plan's from PROVIEW Analysis

Base Case			
	CT	CC	TOTAL
2002	1	1	2
2003	2	3	5
2004	2	5	7
2005	5	9	14
2006	6	10	16
2007	10	10	20
2008	10	12	22
2009	11	15	26
2010	11	15	26
2011	13	17	30
2012	14	21	35
2013	14	26	40
2014	18	28	46
2015	19	33	52
2016	20	38	58
2017	22	45	67
2018	25	49	74
2019	26	55	81
2020	27	61	88
2021	32	68	100

SBO-Smith Unit 3			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	10	10	20
2008	11	11	22
2009	13	13	26
2010	13	13	26
2011	15	15	30
2012	16	19	35
2013	16	24	40
2014	18	28	46
2015	21	31	52
2016	23	35	58
2017	25	42	67
2018	27	47	74
2019	27	54	81
2020	29	59	88
2021	34	66	100

Respondent A			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	10	10	20
2008	11	11	22
2009	13	13	26
2010	13	13	26
2011	14	16	30
2012	16	19	35
2013	16	24	40
2014	18	28	46
2015	20	32	52
2016	21	37	58
2017	24	43	67
2018	27	47	74
2019	28	53	81
2020	29	59	88
2021	35	65	100

Respondent B CC(10yr)			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	10	10	20
2008	11	11	22
2009	13	13	26
2010	13	13	26
2011	14	16	30
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

Respondent B CC(7yr)			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	10	10	20
2008	11	11	22
2009	13	15	28
2010	13	15	28
2011	15	17	32
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

Respondent B CC(20yr)			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	10	10	20
2008	11	11	22
2009	13	13	26
2010	13	13	26
2011	14	16	30
2012	16	19	35
2013	16	24	40
2014	18	28	46
2015	19	33	52
2016	21	37	58
2017	24	43	67
2018	27	47	74
2019	27	54	81
2020	29	59	88
2021	34	66	100

Respondent B CT(10yr)			
	CT	CC	TOTAL
2002	1	1	2
2003	1	4	5
2004	1	6	7
2005	5	9	14
2006	6	10	16
2007	10	10	20
2008	10	12	22
2009	12	14	26
2010	12	14	26
2011	13	17	30
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

Respondent B CT(7yr)			
	CT	CC	TOTAL
2002	1	1	2
2003	1	4	5
2004	1	6	7
2005	5	9	14
2006	6	10	16
2007	10	10	20
2008	10	12	22
2009	13	15	28
2010	13	15	28
2011	15	17	32
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

Respondent B CT(20yr)			
	CT	CC	TOTAL
2002	1	1	2
2003	1	4	5
2004	1	6	7
2005	5	9	14
2006	6	10	16
2007	10	10	20
2008	10	12	22
2009	12	14	26
2010	12	14	26
2011	13	17	30
2012	15	20	35
2013	16	24	40
2014	17	29	46
2015	19	33	52
2016	20	38	58
2017	23	44	67
2018	25	49	74
2019	26	55	81
2020	28	60	88
2021	32	68	100

Respondent C			
	CT	CC	TOTAL
2002	2	0	2
2003	3	2	5
2004	3	4	7
2005	6	8	14
2006	6	10	16
2007	12	10	22
2008	12	12	24
2009	13	15	28
2010	13	15	28
2011	15	17	32
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

Respondent C (Fixed Energy)			
	CT	CC	TOTAL
2002	1	1	2
2003	2	3	5
2004	2	5	7
2005	5	9	14
2006	6	10	16
2007	12	10	22
2008	12	12	24
2009	13	15	28
2010	13	15	28
2011	15	17	32
2012	16	21	37
2013	16	26	42
2014	19	29	48
2015	21	33	54
2016	22	38	60
2017	25	44	69
2018	27	49	76
2019	28	55	83
2020	30	60	90
2021	34	68	102

4. Provide a breakdown of all transmission-related costs associated with each self-build option and all respondents to Gulf's RFP.

RESPONSE:

The Company has decided to group the responses to interrogatories 4, 11, and 12 together because they are all related to transmission impacts and plans. Also, the Company does not perform a 20-year transmission plan as requested in Interrogatories 11 and 12.

The following is a tabulation of the specific transmission improvements and their costs (98$) that are associated with each alternative that Gulf evaluated in either the self-build or RFP process:

SBO Case No. 1 - Daniel Combined Cycle Participation

Construct N. Brewton - Shoal River 230 kV	$ 60.0M
Shoal River - Laguna 230 kV line	$ 46.5M
Daniel CC connection (includes GSU)	$ 4.1M
41.88% share of Ellicott-N.Brewton 230kV	$ 24.1M
8.88% share of Daniel-Big Creek 230 kV	$ 2.1M
TOTAL	$136.8M

SBO Case No. 2 - Mulat Tower Cogeneration Unit

Cogeneration unit connection (Includes GSU)	$ 17.0M
Shoal River - Laguna 230 kV line	$ 46.5M
Crist - Shoal River 230 kV line	$ 20.3M
Ellicott - Crist #2 230 kV line	$ 36.0M
TOTAL	$119.8M

SBO Case No. 3 - Smith CT or CC Units

Smith connection costs (Includes GSU)	$ 4.6M
Ellicott - Crist #2 230 kV line (2003)	$ 36.0M
TOTAL	$ 40.6M

RFP Case No. 1 - Respondent A

2002 improvements:

Construct Shoal River - Laguna 230kv	$46.0M
Construct N. Brewton- Shoal River 230 kV	$45.6M
Facility Connection - Santa Rosa	$6.2M
Facility Connection - Mobile	$1.9M
TOTAL	$ 99.7M

RFP Case No. 2 - Respondent B

2002 improvements:	
Reconductor Chickasaw - S. Hill #1	$ 6.0M
Reconductor Chickasaw - S. Hill #2	$ 6.4M
Reconductor Big Creek - Chickasaw 230 kV	$ 2.1M
Reconductor Blakely Is. - Spanish Fort	$ 2.4M
Reconductor Barry - Crist 230 kV	$ 7.2M
Reconductor Barry - Chickasaw 230 kV	$ 6.5M
Construct Facility - Laguna 230 kV	$26.0M
Facility Connections	$ 2.4M
2009 Improvements:	
Construct N. Brewton - Shoal River 230 kV	$45.6M
TOTAL	$104.6M

RFP Case No. 3 - Respondent C

2002 improvements:	
Reconductor Chickasaw - S. Hill #1	$6.0M
Reconductor Chickasaw - S. Hill #2	$6.4M
Reconductor Big Creek - Chickasaw 230 kV	$2.1M
Construct Shoal River - Laguna 230 kV	$46.0M
Construct N. Brewton - Shoal River 230 kV	$45.6M
2005 Improvements:	
Reconductor Barry - Chickasaw 230 kV	$6.5M
TOTAL	$112.6M

RFP Case No. 4 - Smith Unit 3

2002 improvements:	
Reconductor Chickasaw - S. Hill #1	$ 6.0M
Reconductor Chickasaw - S. Hill #2	$ 6.4M
Reconductor Big Creek - Chickasaw 230 kV	$ 2.1M
Reconductor Blakely Is - Spanish Fort	$ 2.4M
Reconductor Barry - Crist 230 kV	$ 7.2M
Reconductor Barry - Chickasaw 230 kV	$ 6.5M
Smith - Greenwood 115 kV reconductor	$ 1.2M
Smith - Highland City 115 kV reconductor	$ 1.2M
Highland City-Callaway 115 kV reconductor	$ 0.7M
Smith Connections	$ 2.2M
Replace 6 Smith Circuit Breakers	$ 1.2M
Replace 1 Brkr. at Laguna & Highland City	$ 0.3M
2009 Improvements:	
Construct N. Brewton - Shoal River 230 kV	$ 45.6M
TOTAL	$ 83.0M

The following transmission system improvements are those which are contained in Gulf's Capital Budget. These items are compared on the basis of their status both before and after the decision to pursue Smith Unit 3. As shown below, the addition of Smith Unit 3 does not have a significant impact on the transmission plan. However, there would have been significant impacts had a different alternative been chosen. Two of the items are associated specifically with generation in the Bay County area.

	BEFORE SMITH 3		AFTER SMITH 3	
ITEM DESCRIPTION	**IN-SERVICE DATE**	**CAPITAL COST K$**	**IN-SERVICE DATE**	**CAPITAL COST K$**
Crist-Blackwater 115 kV reconductor	2001	7,900	2001	7,900
Shoal River-ValP 115 kV reconductor	2001	2,900	2001	2,900
Highland City-Callaway 115 kV reconductor(1)	N/A	N/A	2006	1,200
Holmes Creek-Scholz 115kV reconductor	1999	7,206	1999	6,206
Crist-Pace 115 kV reconductor	2001	1,600	2001	1,600
ValP-Niceville 115 kV reconductor	2001	720	2001	720
Smith-Highland City 115 kV reconductor (1)	2001	N/A	2001	1,200
Smith-Greenwood 115 kV reconductor (1)	2001	N/A	2001	1,200
Shoal River-Glendale Tap new line	2001	2,400	2001	2,900
Callaway Capacitor bank addition	2001	490	2005	490
Scholz Capacitor bank addition	1999	450	1999	450
Smith-Laguna Bch. line upgrade (2)	N/A	N/A	2006	160
Laguna Bch.-Lullwater line upgrade (2)	N/A	N/A	2006	520
Smith & Laguna Bch. breaker replacement (1)	N/A	N/A	2002	2,210

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Notes: (1) This improvement is directly associated with additional generation located in Bay County and was inadvertently omitted from the Petition for Need Determination. Amended figures will be subsequently filed to correct this oversight. The costs associated with these improvements were included in the Smith Unit 3 cost used in the RFP evaluation process. No change in the relative cost-effectiveness occurs from this change.

(2) This improvement is a local area problem and is not associated with the addition of generation in the Bay County area.

8. Discuss the current status of negotiation with the RFP respondents "with the best offers", as stated at page 69 of the Need Study. Explain the chances that an RFP project will be signed and build instead of Smith Unit 3.

RESPONSE:

The reference on page 69 of the Need Study was relative to the gas supply Request for Proposals (RFP), not the capacity RFP. Gulf is continuing to pursue natural gas supply offers in order to achieve the best fuel costs for Smith Unit 3.

16. On page 49 of the Need Study, it states, in part, "if necessary, adjustments were made to reflect any cost differences due to natural gas supply at a point other than the Henry Hub, and any differences due to the specifics of the proposal, such as a commodity price adder." Indicate the amount of the adjustment ($/MMBtu), if any, that was made during the evaluation of all self build alternatives and all RFP respondents. (State whether costs are in nominal or in real dollars.)

RESPONSE:

All prices are given in nominal dollars. There is an assumed basis difference of $0.06 per MMBtu was used when comparing Henry Hub Index Prices to Florida Gas Transmission - Zone 3 Index Prices. An additional $0.05 per MMBtu basis difference was used for gas delivered at Mobile Bay Plants from FGT - Zone 3. The adjustment to the commodity price depends on the assumed point of delivery location from the Henry Hub. The tabulation below shows the adjustments made to the gas commodity prices for the various alternative options based on the delivery from Henry Hub.

An additional $.02 premium was applied to all of the Self-build prices as a fee to secure gas availability. This was not done in the RFP process since the respondents were making quotes to Southern and were specifying its firmness.

To all the natural gas commodity prices, the appropriate transportation cost was added to determine delivered fuel cost.

SELF-BUILD/RESPONDENT	COMMODITY PRICE BASIS	COMMODITY PRICE ADJUSTMENT
Self-Build Smith option	Henry Hub	<$ .06>
Self-Build Daniel option	Henry Hub	$ .00
Self-Build Mulat Tower option	Henry Hub	<$ .11>
Respondent A	Henry Hub +4%	$ .00
Respondent B	Henry Hub	$ .00
Respondent C	Henry Hub	$ .00
RFP Smith option	Henry Hub	<$ .06>

17. Identify and provide the forecast of all fixed and variable costs ($/MMBtu) for transporting natural gas for all self build alternatives and all RFP respondents from 2002 to 2021. Include any charge, fee, tax, levy or any other monetary or non-monetary consideration to transport natural gas. State all assumptions. (State whether costs are in nominal or real dollars.)

RESPONSE:

There were no fuel estimates performed for self-build option "Mulat Tower" since this concerned a cogeneration facility that had a delivered gas price and annual escalation provided as part of the input assumptions. Likewise, the fuel for Respondent C of the RFP analysis was assumed to be that which was quoted. The fuel projections used for Respondents A and B of the RFP analysis also had backup oil components added to their natural gas prices to account for those hours the gas would not be available under the terms of their non-firm gas proposal.

The remainder of this response was filed with Letter of Intent to request Confidential treatment.

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18. For all self build generation alternatives and all RFP respondents, indicate how Gulf Power or the RFP respondent plans to replace the capacity, energy, or both when the primary fuel is not available.

RESPONSE:

All self-build options included dedicated firm natural gas supply as well as gas storage. In the event that no gas supply is available the unit will not run, and any necessary replacement energy will be procured from the market. Respondent A had fuel oil backup at only one of the facilities, gas storage was included, but firm gas transportation was not offered. Respondent B included fuel oil backup at the site and eventually included dedicated firm gas transportation for their combined cycle proposals. No fuel oil backup was provided by Respondent C, but additional cost was itemized in their proposal for dedicated firm natural gas delivery.

19. Provide Gulf Power's system-wide forecast for delivered coal prices from 2002 to 2021 in dollars per million BTU ($/MMBtu) and dollars per ton ($/ton). State whether costs are in nominal or real dollars. Also include the following assumptions: type of coal; origin of coal; heat content; ash content; moisture content; and sulfur content.

RESPONSE:

There is no Gulf Power system-wide forecast for delivered coal (interrogatory #19) or delivered oil (interrogatory #20). In an effort to provide relative fuel cost information, Gulf has expanded the commodity (non-delivered) information originally provided in Table 5-1 of the Need Study to include additional years and quality information. These prices are the basis of delivered fuel prices in the planning studies. Site-specific delivery costs can be added to determine the total delivered fuel costs. All Prices are in Nominal Dollars.

	COAL		NAT. GAS		OIL	
	$/MMBtu	$/Ton	$/MMBtu	$/MCF	$/MMBtu	$/BBl
1999	1.071	25.71	2.28	2.35	3.94	28.75
2000	1.080	25.92	2.28	2.35	4.06	29.64
2001	1.089	26.13	2.28	2.35	4.18	30.54
2002	1.098	26.34	2.28	2.35	4.30	31.47
2003	1.107	26.56	2.28	2.35	4.43	32.43
2004	1.115	26.77	2.28	2.35	4.58	33.43
2005	1.125	26.99	2.47	2.54	4.72	34.78
2006	1.134	27.21	2.62	2.70	4.87	36.18
2007	1.143	27.43	2.79	2.87	5.02	37.64
2008	1.152	27.65	2.96	3.05	5.18	39.17
2009	1.162	27.88	2.98	3.07	5.34	40.75
2010	1.171	28.10	3.00	3.09	5.57	42.42
2011	1.180	28.33	3.07	3.16	5.80	44.13
2012	1.190	28.57	3.15	3.26	6.04	45.87
2013	1.200	28.80	3.22	3.32	6.29	47.68

2014	1.210	29.03	3.30	3.40	6.55	49.57
2015	1.220	29.27	3.38	3.48	6.82	52.01
2016	1.230	29.51	3.45	3.55	7.10	54.56
2017	1.240	29.76	3.71	3.82	7.39	57.25
2018	1.250	30.00	3.98	4.10	7.69	60.06
2019	1.260	30.25	4.28	4.41	8.00	63.02
2020	1.271	30.50	4.42	4.55	8.40	66.12
2021	1.282	30.76	4.58	4.72	8.82	69.22
2022	1.292	31.01	4.74	4.88	9.26	72.32

(1) Coal is Central Appalachia FOB Price, 12,740 Btu, 1.0% Sulfur, 9.0 Ash, 8% Moisture.

(2) Gas is FOB Mobile Bay, 1.030 MMBtu/MCF.

(3) Oil is FOB Gulf Coast, 140,620 Btu/gal, 0.45% Sulfur, 0% Ash.

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20. Provide Gulf Power's system-wide forecast for delivered oil prices from 2002 to 2021 in dollars per million BTU (\$/MMBtu) and dollars per barrel (\$/barrel). State whether costs are in nominal or real dollars. Also include the following assumptions: heat content; ash content; and sulfur content.

RESPONSE:

See tabular response to Interrogatory number 19

21. Indicate the annual level of NOx emissions that Gulf Power expects from the proposed Smith Unit 3 from 2002 through 2021. State assumptions.

RESPONSE:

The maximum potential NOx emissions from Smith Unit 3 are estimated to be 760 tons of NOx per year. This estimate is based on a 100% capacity factor assumption for Smith Unit 3 for the years 2002 through 2021. EPA requires the use of maximum potential emission estimates for al air environmental impact statements. No other emission estimates are available.

22. Page 76 of the Need Study states, in part, "Gulf is pursuing an air emission strategy that will reduce NOx emissions from one of the existing Smith generating units leading to a net reduction in total NOx emissions for the entire plant." Discuss Gulf Power's plans to reduce total NOx emissions for its Smith Plant.

RESPONSE:

Gulf Power proposes to offset new NOx emissions from Smith Unit 3 by reducing emissions at Smith Unit 1 to amounts necessary to obtain a net reduction in NOx at the facility. Smith Unit 1 is a coal-fired boiler with annual emissions of 3594 tons of NOx. Gulf Power's plan is to cap NOx emissions on Smith Unit 1 at 2832 tons per year. This amount is equal to or less than potential emissions (760 tons) at the maximum capacity of Unit #3 at Smith. Gulf Power will accomplish the reductions through installing low NOx burner technology and GNOCIS, a Generic NOx Control Intelligent System on Unit 1. The low NOx burner technology on Smith Unit 1 will reduce emissions by reducing the amount of oxygen available for the combustion process and GNOCIS assists in this reduction by operating the total burner system more efficiently through neural network technology.

23. Itemize the capital and O&M costs of the Selective Catalytic Reduction (SCR) system that Gulf Power used while evaluating the cost-effectiveness of its self-build options and RFP responses.

RESPONSE:

SELECTIVE CATALYTIC REDUCTION COSTS

Capital Costs	($1998)
Direct Vendor - Materials D&E	$2,919,140
Indirects (10%)	$291,914
Total Installed Equipment	$3,211,054

Annual O & M Costs	($1998)
Ammonia	$115,676
Maintenance	$29,620
O&M Labor	$185,500
Station Service	$13,808
Pressure Drop Penalty	$318,856
SCR Catalyst Replacement	$306,872
Total O&M Costs	$970,332

24. The Need Study states, in part, "(c)ondenser cooling for Smith Unit 3 will be accomplished by a closed-cycle cooling tower system, which will minimize cooling water withdrawals and discharges." Itemize the capital and O&M costs for the closed-cycle cooling tower system, discussed on page 76 of the Need Study, that Gulf Power will use for Smith Unit 3.

RESPONSE:

Cooling Tower Chemical Feed System Equipment Cost

Nonoxidizing Biocide Skid	$ 12,000
Dispersant Skid	$ 12,000
Corrosion Inhibitor Skid	$ 10,000
Sulfuric Acid Skid	$ 30,000
Sodium Hypochlorite Skid	$ 20,000
Cooling Tower Feed Skid Enclosure	$ 20,000
Chemical Containment	$ 10,000
Bulk Tank Pads	$ 10,000
Installation Labor	$ 51,000
TOTAL	$ 175,000

Cooling System Equipment Cost Data

Circulating Water Piping, Valves Thrust Blocks, Excavation, etc.	$1,181,000
Circulating Water Pump Structure	$ 46,000
Circulating Water Pumps (CWP)	$ 524,000
Circulating Water Pump Motors	$ 229,000
Cooling Tower Foundation	$ 132,000
Cooling Tower Basin	$ 302,000
Cooling Tower	$2,800,000
Cooling Tower Motor Control Center(MCC)	$ 97,000
Cooling Tower MCC Building	$ 39,000
Cooling Tower MCC Cable/Conduit	$ 169,000
Cooling Tower Blowdown Piping	$ 13,000
Cooling Tower Basin Outlet	$ 105,000
Condenser	$2,477,000
Condenser Vacuum Pumps	$ 277,000
Condenser Vac. Sys. Piping/Valves	$ 23,000
Chemical Feed House	$ 53,000
TOTAL	$8,467,000

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The following shows the estimated operating and maintenance requirements for the cooling system:

Cooling Tower Station Service Operating Requirements:

10 Fans @ 200 BHP/Fan (2,000 BHP) ~ 1500 kW

Circulating Water Pump (CWP) Station Service Operating Requirements:

2 CWPs @ 63,000 GPM/Pump (2,680 BHP) ~ 2000 kW

Condenser Vacuum Pump Station Service Operating Requirements:

2 Vacuum Pumps @ 150 BHP/pump (300 BHP) ~ 224 kW

Cooling system maintenance costs (tower, condenser, pumps, etc.) are currently estimated to be approximately $50,000 to $100,000/year.

25. Page 76 of the Need Study states, in part, "(f)rom an environmental standpoint, the proposed facility will have a net positive impacts." Please elaborate further on this statement.

RESPONSE:

As stated in the Need Study, the two principal environmental issues associated with operation of Smith 3 are NOx emissions and thermal impacts from the discharge of cooling water.

Cooling tower blowdown from Smith Unit 3 will join with the existing cooling water discharge of Smith Units 1 and 2 before ultimately being discharged into West Bay. Because the blow-down from Smith Unit 3 will be taken from the cold-side of the cooling tower, there will be a slight decrease in the overall temperature of the discharge water entering West Bay.

Gulf Power plans to offset new NOx emissions from Smith Unit 3 by reducing NOx emissions at the existing Smith Unit 1. This will be accomplished by installing low NOx burner technology and a neural network software package on Smith Unit 1. The NOx emission reduction from Smith Unit 1 will more than offset the proposed NOx emissions from Smith Unit 3.

27. Provide a description of each of Southern's interconnection points with other utilities or utility systems. Include the import capability, in megawatts (MW) and megavars (MVAR), of each of these interconnection points individuality and of the Southern Company system as a whole.

RESPONSE:

See Attachment 27-1.

Attachement 27-1
Staff's 1st set of Interrogatories
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TABULATION OF SOUTHERN SYSTEM INTERFACES & IMPORT CAPABILITY

Interfaces with Indicated Control Areas	Interface Composed of Following Transmission Lines	Thermal Rating MVA	1999 OASIS TTC Imports Into Southern MW
Duke Power Company	Norcross-Oconee 500kv	2439	1049
	Bio-ANP Hartwell-Hartwell Dam 230kv	664	
South Carolina Electric & Gas	Vogtle-Savannah River Plant 230kv	756	229
	McIntosh-McIntosh Tap 115kv	240	
	Acadia Tap-Urquhart 115kv (Normally Open)	151	
	South Augusta-Urquhart 115kv (Normally Open)	151	
South Carolina Public Service Authority	McIntosh-Bluffton 230kv	829	507
Tennessee Valley Authroity	Bowen-Sequoyah 500kv	2598	1204
	Rock Spring-Oglethorpe 161kv	446	
	East Dalton-Widows Creek 230kv	602	
	Miller-Bellefonte 500kv	1732	
	Miller-Lowndes 500kv	1732	
	Attalla-Albertville 161kv	192	
	Blountsville-guntersville 115kv	94	
	Haleyville-Wilson 161kv	282	
	S. Vernon Tap-Lowndes 161kv	180	
SEPA (Connections to VACAR)	Evans-Thurmond Dam 115kv #1	135	Included with Duke, SCE&G and SCPSA
	Evans-thurmond Dam 115kv #2	135	
	Double Branches-thurmond Dam 115kv	57	
	Lexington-Russell Dam 230kv	497	
Entergy	Logtown-slidell 230kv	797	1078
	Hattiesburg SW-Bogalusa 230kv	458	
	Collins-magee 115kv	76	
	NWForest-Morton 115kv	120	
	Daniel-McKnight 500kv	1800	
Florida	Hatch-Duval 500kv	2598	1276
	Thalmann-Duval 500kv	2598	
	Kingsland-Yulee 230kv	497	
	Pinegrove-Sterling-Swannee 230kv	509	
	Pinegrove-Wrights Chapel-Jasper 115kv	43	

	Twin Lakes-Suwannee 115kv	124	
	Tarver-Jasper 115kv	60	
	Scholz-Woodruff 115kv	124	
	Callaway-Port St. Joe 230kv	433	
	South Bainbridge-Sub 20 230kv	497	
Alabama Electric Cooperative	West Point Dam(SEPA)-Opelika 115kv	216	393
	George Dam (SEPA)-Capps SW 115kv	155	
	George Dam (SEPA)-Judson Tap 115kv	79	
	R.F. Henry Dam (SEPA)-Gordonsville Jct 115kv	137	
	Greenville-Belleville 230kv	602	
	Boise Cascade-Lowman 115kv	212	
	McIntosh-McIntosh (AEC) 115kv	424	
	W. McIntosh-McIntosh 115kv	415	
	W. McIntosh-Lowman 230kv	602	
	Pinkard-Opp 230kv	349	
	N. Brewton-Opp 230kv	349	
	Flomation-Atmore 115kv	212	
	Perdido-Atmore 115kv	212	
	Boise Cascade Tap-Lowman 115kv	212	
	Niceville-Blue Water 115kv	216	
	Scholz-Gaskin 115kv	100	
	Cristal Beach-Blue Water 115kv	161	
	Callaway-Gaskin 115kv	100	
	Bonifay-Bonifay (AEC) 115kv	209	
	Monroe-Belleville 230kv	502	
	Monroe-Arn 230kv	502	
Southern Mississippi Electric Power Authority	Purvis 230/115kv Transformer Ckt 1	168	0
	Purvis 230/115kv Transformer Ckt 2	168	

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32. Please explain the reasons why Gulf does not plan to use a backup fuel source for the proposed Lansing Smith Unit 3?

RESPONSE:

From a system planning perspective, based on the Company's reliability criteria, the proposed Smith Unit 3 does not need a backup fuel source. Gulf will use a firm supply of natural gas (including firm transportation) as the exclusive fuel source for Smith Unit 3. The Southern electric system, of which Gulf is part, has a large amount of generating capacity that does not rely on natural gas. In the unlikely event of an interruption of the natural gas supply, the Southern electric system resources provide sufficient reserves to Gulf.

Although Smith Unit 3 is a significant capacity resource relying on a single fuel source, according to Gulf's planning criteria, the Company will continue to serve its customers in the event of a reasonably foreseeable interruption in the natural gas supply. Other Southern operating companies are adding combined cycle units of greater capacity than that of Smith Unit 3 and are not providing for backup fuel supplies. The other Southern operating companies, like Gulf, will use firm gas supplies and transportation as well as off-site natural gas storage capacity.

In addition, there are environmental benefits from utilizing natural gas as the exclusive fuel source. Providing backup fuel capability for Smith Unit 3 would be a cost that the customers would have to bear without an associated benefit from a reliability standpoint.

FPSC Staff's Second Set
Of Interrogatories
Docket No. 990325-EI
GULF POWER COMPANY
June 2, 1999
Item No. 33

33. How would an interruption of the natural gas supply to the proposed Lansing Smith Unit 3 impact reliability in both the Panama City, Florida, region of Gulf's service territory, and throughout all of Gulf's territory?

RESPONSE:

An interruption of the natural gas supply to Smith Unit 3 that causes the loss of the unit would not result in a corresponding loss in service to the customers in either the Panama City area or anywhere in Gulf's service area. Gulf's planning criteria calls for maintaining service to its customers for the loss of any generating unit and any transmission element (line or autotransformer). Therefore, even if there were a total gas supply interruption causing Smith Unit 3 to come off line at the same time as a loss of a transmission facility, the Company would still be able to provide service to its customers.

It is important to note that outages due to gas supply problems, although possible, occur with far less frequency than other outages, such as those caused by problems with boiler or auxiliary equipment associated with the unit. A backup fuel source would do nothing to prevent outages associated with these other events that are much more likely to occur than a gas supply interruption.

FPSC Staff's Second Set
Of Interrogatories
Docket No. 990325-EI
GULF POWER COMPANY
June 2, 1999
Item No. 34

34. If Gulf were to have a backup fuel source for the proposed Smith Unit 3, please describe the type of fuel to be chosen (commodity and storage) and the expected amount of fuel stored (number of days at 100% dispatch).

RESPONSE:

The fuel would likely be No.2 low sulfur fuel oil stored in an atmospheric tank. At full load, assuming no duct burning in the HRSG, the unit would consume approximately 674,000 gallons per day. A minimum 3-day supply would require slightly more than 2 million gallons of useable storage. Given the difficulty in getting a sufficient quantity of trucks to the site to keep up with the demand, a 5-day supply (3.4 million gallons) might be preferable.

Unfortunately, fuel oil cannot be stored indefinitely. Long term storage requires the use of stabilizers and inhibitors. Many users have found that it is better to burn oil occasionally and thereby turn the tank volume over. Having to burn the fuel oil at times when it is not necessary, for the purpose of preventing its deterioration, would increase the operating cost of the unit. Also, this periodic use of fuel oil on other than an emergency basis has an adverse cost impact on Gulf and its customers through a change in environmental permitting and operating requirements.

FPSC Staff's Second Set
Of Interrogatories
Docket No. 990325-EI
GULF POWER COMPANY
June 2, 1999
Item No. 35

35. Please provide an estimate of the cost of the backup fuel storage for the proposed Lansing Smith Unit 3 using the assumptions made by Gulf in responding to Interrogatory #34. Please provide the estimate in both a Net Present Value Cost per Kilowatt-year (NPC$/kw-yr) and in total dollars, both nominal and in present worth revenue requirements. Include the capital, operations and maintenance (O&M), and any other variable costs associated with maintaining the backup fuel source for the unit.

RESPONSE:

Assuming a 3-day supply, the expected capital cost would be approximately $6 million. This estimate further assumes that the added facilities necessary to support on-site oil storage and related backup fuel burning capability could be installed without the need for additional wetland mitigation. The specific amounts of O&M increases necessary to support back-up fuel capability have not been determined. However, it is known that the number of fired hours on oil will impact combustion turbine maintenance. There will also be labor costs associated with scheduling and receiving oil. Added to this will be the carrying costs for the fuel inventory, estimated to be $400,000 per year.

As pointed out in Gulf's Need Study, the environmental strategy for NOx emissions is to provide offsets of NOx emissions from existing Smith Plant units. If Gulf is required to provide fuel oil as a backup fuel for Smith Unit 3, then the maximum potential emissions on oil must enter into the environmental permitting process. The two major impacts of this change are (1) the additional cost for NOx compliance and (2) the cost associated with delaying the project beyond the needed June 2002 in-service date. Because the use of fuel oil as a backup negates the NOx offset strategy, there would be additional environmental compliance costs and there will no longer be the benefit of a total reduction in the NOx output of the generating units at the Smith site.

The $6 million capital cost referred to above does not include the additional cost to comply with air emission standards for NOx based on consideration of the maximum potential use of #2 low-sulfur fuel oil as a backup fuel. The capital cost for Selective Catalytic Reduction (SCR) is estimated at just over

$2,000,000 and the O&M for SCR is approximately $1,000,000 per year.

The environmental permitting process will be delayed as a result of going to fuel oil as a backup fuel for Smith Unit 3. This delay will postpone the in-service date for the unit by approximately one year and require Gulf to purchase replacement power at prices that are clearly higher than that of Smith Unit 3. Under the market conditions known today, this replacement power could cost tens of millions of dollars for that one-year delay.

This additional cost of providing backup fuel capability is of particular concern since there is no reliability benefit to be derived. Gulf's customers are not going to suffer a loss of service as a result of an outage caused by a natural gas pipeline interruption. However, the environment would suffer as a result of having to provide backup fuel for Smith Unit 3.

17. Provide all documents which Gulf Power used to evaluate NOx, SO2, and particulate emission levels from the proposed Smith Unit 3.

RESPONSE:

See the Self-Build Emissions (Case 1-5) and Smith Unit 1 PSD Netting Out Worksheet attached.

FOV - 11

Smith Unit 1 PSD Netting Out Worksheet

03/29/99 Revised

Baseline Heat Input Calculation

1996 Smith 1

Coal	**520,766 tons @ 23.55 MBTU/ton = 12264039 MBTUs**
Oil	**65.9 K gallons @ 138.5 MBTU/Kgallon = 9127 MBTUS**
Total	**(Coal MBTUs + Oil MBTUS = 12273166 MBTUS**

1998 Smith I

Coal	**522,256.50 tons @ 23.53 MBTU/ton = 12288695 MBTUs**
Oil	**70.76 K gallons @ 138.48 MBTU/Kgallon = 9799 MBTUS**
Total	**(Coal MBTUs + Oil MBTUS = 12298494 MBTUS**

1996-98 Avg. **(12273166 + 12298494)/2 = 12285830**

Note: 1997 not used in averaging plan as representative due to 37 day outage during year.
1996-98 agreed on by Clair Fancy as baseline years for this project 1/25/99

Baseline NOx Emissions

1996 Smith I	**12273166 MBTUs x .614 lbs/MBTUs (CEMS data)/2000 = 3768 NOx Tons**
1998 Smith I	**12298494 MBTUs x .557 lbs/MBTUs (CEMS data)/2000 = 3425 NOx Tons**
1996-98 Avg	**(3768 + 3425)/2 = 3597 NOX tons**

FDEP/Gulf Power Agreement to use 1996 + 1998 Avg for Baseline PSD Netting Calculation.

1996+98 Avg Tons = 3597 NOx
1996+98 NOx Avg Rate = .586 lbs/mbtu
1996+98 NOx Avg Rate @ 21.3% Control = .461 or 2832 NOx tons
1996+98 NOx Avg Rate @30% Control = .410 or 2519 NOx tons
1996+98 Avg Heat Input = 12285830 MBTUs

NOx CCCT Emissions	**NOx Tons**	**CO Tons**	**Part Tons**	**VOC Tons**
1000 hours Power Aug. at 13.7 ppm or 116 lb/hr(2) =	116	124	33	20
7760 hours at 10.4 ppm or 83 lb/hr per CT (2) =	644	585	162	79
total per yr =	760	709	195	99

Smith 1NOx Ton Reduction using 1996+98 Avg Baseline		
@21.3% Reduction =	3597-2832	765 Tons
@30% Reduction =	3597-2519	1078 Tons

Net NOx Reduction (Smith I less CCCT Estimates)		
@21.3% Reduction Scenario =	**765-760 =**	**5 Tons**
@30% Reduction Scenario =	**1078-760 =**	**318 Tons**

Future Year Impact Analysis

	Year	**Annual Heat Input mmBtu**	**Actual NOx Rate**	**Actual NOx Tons**	**Estimated NOx Tons @21.3%**	**Estimated Reduction NOx Tons**	**Estimated NOx Tons @30%**	**Estimated Reduction NOx Tons**
SMITH HC 1	1994	8798530						
SMITH HC 1	1995	12562424	0.635	3989				
SMITH HC 1	1996	12273166	0.614	3768				
SMITH HC 1	1997	10776657	0.612	3298				
SMITH HC 1	1998	12298494	0.557	3425				
SMITH HC 1	2000	9252020			2133		1897	
SMITH HC 1	2001	8864413			2043		1817	
SMITH HC 1	2002	8125687			1873	964	1666	1171
SMITH HC 1	2003	6949575			1602	1235	1425	1412
SMITH HC 1	2004	7213593			1663	1174	1479	1358
SMITH HC 1	2005	6816910			1571	1266	1397	1440
SMITH HC 1	2006	7285515			1679	1158	1494	1343
SMITH HC 1	2007	5646277			1301	1536	1157	1680
SMITH HC 1	2008	6984874			1610	1227	1432	1405
SMITH HC 1	2009	9447624			2178	659	1937	900
SMITH HC 1	2010	8904809			2053	784	1825	1012

POD #17

Gulf Self-Build Emissions
(Revised 4/9/99)

CT Emissions @ Duct Burner Inlet (vol. %)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
O_2	12.08	12.08	11.04	12.29	12.29	12.57
CO_2	3.84	3.84	3.84	3.89	3.89	3.87
H_2O	10.31	10.31	15.24	8.91	8.91	7.57
N_2	72.9	72.9	69.06	74.03	74.03	75.09
Ar	0.87	0.87	0.82	0.88	0.88	0.9
NOx	0.001	0.001	0.0014	0.001	0.001	0.001
CO	0.0013	0.0013	0.0013	0.0014	0.0014	0.0014
VOC (non-methane/non-ethane)	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Part. PM-10	0.0013	0.0013	0.0012	0.0012	0.0012	0.0011

CT Emissions (ppmvd @ 15% O_2)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
NOx	9.1	9.1	12.1	9	9	9
CO	12	12	11.4	12.1	12.1	12.2
VOC (non-methane/non-ethane)	2.4	2.4	2.5	2.5	2.5	
Part. PM-10 (Mg/N-M3)	6.8	6.8	6.4	6.5	6.5	5.9

Case Summary
Case 1 - 95 deg ambient w/o supplemental firing
Case 2 - 95 deg ambient over pressure
Case 3 - 95 deg ambient power augmentation
Case 4 - 65 deg ambient w/o supplemental firing
Case 5 - 65 deg ambient over pressure
Case 6 - 0 deg ambient over pressure

Note: All VOC given as non-methane, non-ethane

Case 1 Combustion Products

	Burner inlet (lb/hr)	Burner outlet (lb/hr)	Burner outlet (ppmvd @ 15% O_2)	Duct burner heat input (MMBtu/lb LHV)
O_2	460428	460428		0
CO_2	201292	201292		
H_2O	221239	221239		
N_2	2432507	2432507		
Ar	41396	41396		
NOx	56	56	9.1	
CO	45	45	12	
VOC	5.2	5.2	2.4	
Part. PM-10	18	18	6.8 Mg/N-M3 (actual O2)	
Total	3357000	3357000		

Case 2 Combustion Products

	Burner inlet (lb/hr)	Burner outlet (lb/hr)	Burner outlet (ppmvd @ 15% O_2)	Duct burner heat input (MMBtu/lb LHV)
O_2	460428	424722		194.4
CO_2	201292	226290		
H_2O	221239	241177		
N_2	2432507	2432709		
Ar	41396	41398		
NOx	56	73.3	10.6	
CO	45	66.6	15.8	
VOC	5.2	8.7	3.6	
Part. PM-10	18	19.1	7.2 Mg/N-M3 (actual O2)	
Total	3357000	3366485		

Case 3 Combustion Products

	Burner inlet (lb/hr)	Burner outlet (lb/hr)	Burner outlet (ppmvd @ 15% O_2)	Duct burner heat input (MMBtu/lb LHV)
O_2	443584	393457		272.85
CO_2	212197	247282		
H_2O	344746	372730		
N_2	2429182	2429431		
Ar	41131	41132		
NOx	79	103	13.6	
CO	45	106	22.9	
VOC	5.6	15.3	5.8	
Part. PM-10	18	19.5	6.9 Mg/N-M3 (actual O2)	
Total	3471000	3484315		

Case 4 Combustion Products

	Burner inlet (lb/hr)	Burner outlet - (lb/hr)	Burner outlet (ppmvd @ 15% O_2)	Duct burner heat input (MMBtu/lb LHV)
O_2	489002	489002		0
CO_2	212868	212868		
H_2O	199593	199593		
N_2	2578683	2578683		
Ar	43710	43710		
NOx	59	59	9	
CO	48	48	12.1	
VOC	5.6	5.6	2.5	
Part. PM-10	18	18	6.5 Mg/N-M3 (actual O2)	
Total	3524000	3524000		

Case 6 Combustion Products

	Burner inle (lb/hr)	Burner outle (lb/hr)	Burner outle mvd @ 15%	burner heat input MBtu/lb LHV)
O_2	548160	517598		166.9
CO_2	232105	253566		
H_2O	185856	202973		
N_2	2866728	2867206		
Ar	48996	49002		
NOx	64	78.8	10.1	
CO	53	71.5	15	
VOC	6	9.3	3.4	
Part. PM-10	18	18.9	6.2 Mg/N-M3 (actual O2)	
Total	3882000	3890547		

Case 5 Combustion Products

	Burner inlet (lb/hr)	Burner outlet (lb/hr)	Burner outlet (ppmvd @ 15% O_2)	Duct burner heat input (MMBtu/lb LHV)
O_2	489002	455093		184.62
CO_2	212868	236608		
H_2O	199593	218527		
N_2	2578683	2578879		
Ar	43710	43712		
NOx	59	75.4	10.4	
CO	48	68.5	15.5	
VOC	5.6	8.9	3.5	
Part. PM-10	18	19	6.8 Mg/N-M3 (actual O2)	
Total	3524000	3533014		

EMISSION ESTIMATES & OPERATIONAL RECOMMENDATION

New Optional Scenario
Normal Operation of CCCT with Over Pressure & Over Sized Duct Burner
Plus Power Augmentation Mode with Over Pressure & Over Sized Duct Burner

	Case 5 # Hours Base Load With DB	Case 3 # Hours Power Aug Plus DB	NOX tons *	% Reduction Required @ Smith 1	CO tons *	VOC tons *	Part 2.5 tons *
	8260	500	742	20.6%	681	89	183
Recommended Operating Scenario is 7760 hours/1000hours =	7760	1000	757	21.0%	701	93	184
	7260	1500	772	21.5%	722	96	184
	6860	1900	784	21.8%	738	99	184

* All calculations based at 110% of Case values above.

Staff's First Request for
Production of Documents
Docket No. 990325-EI
GULF POWER COMPANY
April 19, 1999
Item No. 18

18. Provide all documents which Gulf Power used to evaluate proposed Smith Unit 3's impact of NOx, SO2, particulate compliance levels for the Smith Plant, Gulf Power, and the Southern Company.

RESPONSE:

See the Gulf Power memo to Gregg M. Worley (EPA) 4/5/99 attached.

POD # 18

One Energy Place
Pensacola, Florida 32520

850.444.6111

GULF POWER
A SOUTHERN COMPANY

Certified Mail

April 6, 1999

Mr. Gregg M. Worley
EPA Region IV Federal Center
Air and Radiation Technology Branch
61 Forsyth St. , SW
Atlanta, GA 30303-8960

Dear Mr. Worley:

RE: Lansing Smith Electric Generating Plant
Oris Code: 643

Thank you for reviewing Gulf Power's proposed new combined cycle electric generating project at Lansing Smith located near Panama City, Florida. As previously discussed, Gulf Power believes the project as proposed would not be applicable to PSD for nitrogen oxides (NOx) due to offsets obtained from reductions on Lansing Smith Unit 1. The proposed control strategy for Lansing Smith Unit 1 is low NOx burner control technology and GNOICS, a Generic NOx Control Intelligent System.

EPA's initial review of this project revealed no restrictions regarding the use of nitrogen oxide reductions at Lansing Smith Unit 1 for offset consideration, but identified concern on how the project would effect the Southern Company NOx Averaging Plan under the Acid Rain program. More specifically, how Gulf Power would assure EPA that credits incurred for the PSD offset would not be double counted under the NOx Averaging Plan. To address this issue, Gulf Power proposes to evaluate the margin of compliance of the Southern Company NOx Averaging Plan each year and determine if the margin of compliance is within the influence of Lansing Smith Unit 1. Should the plan's margin of compliance be less than .001 lbs/mbtu, a default value equal to the unit's pre-offset emission rate would be substituted for actual emissions for Lansing Smith Unit 1 for that year and the Southern Company NOx Averaging Plan would be re-calculated using the default value. If the plan's margin of compliance is greater than .001 lbs/mbtu, then no change would be made to the actual emissions recorded for Lansing Smith Unit 1 and the compliance evaluation would stand "as is".

Gulf Power believes this review is a fair method to evaluated the influence of Lansing Smith because Unit 1 accounts for less than 1% of the total weighted average of the Southern Company NOx Averaging Plan. One percent of the weighted average is equivalent to less than .001 lbs/mbtu of the compliance margin. Attached is suggested permit language outlining the above evaluation scenario with a copy of the Southern Company NOx Averaging Plan Worksheet.

Please provide confirmation of EPA's previous PSD evaluation of this project and comment on Gulf Power's NOx averaging evaluation plan so the permitting of this project will remain on a timely basis.

If you have any questions or need further information regarding this project, please call or email me at (850) 444-6527 or gdwaters@southerco.com, respectively.

Sincerely,

Q.E.P.

G. Dwain Waters, Q.E.P.
Air Quality Programs Coordinator

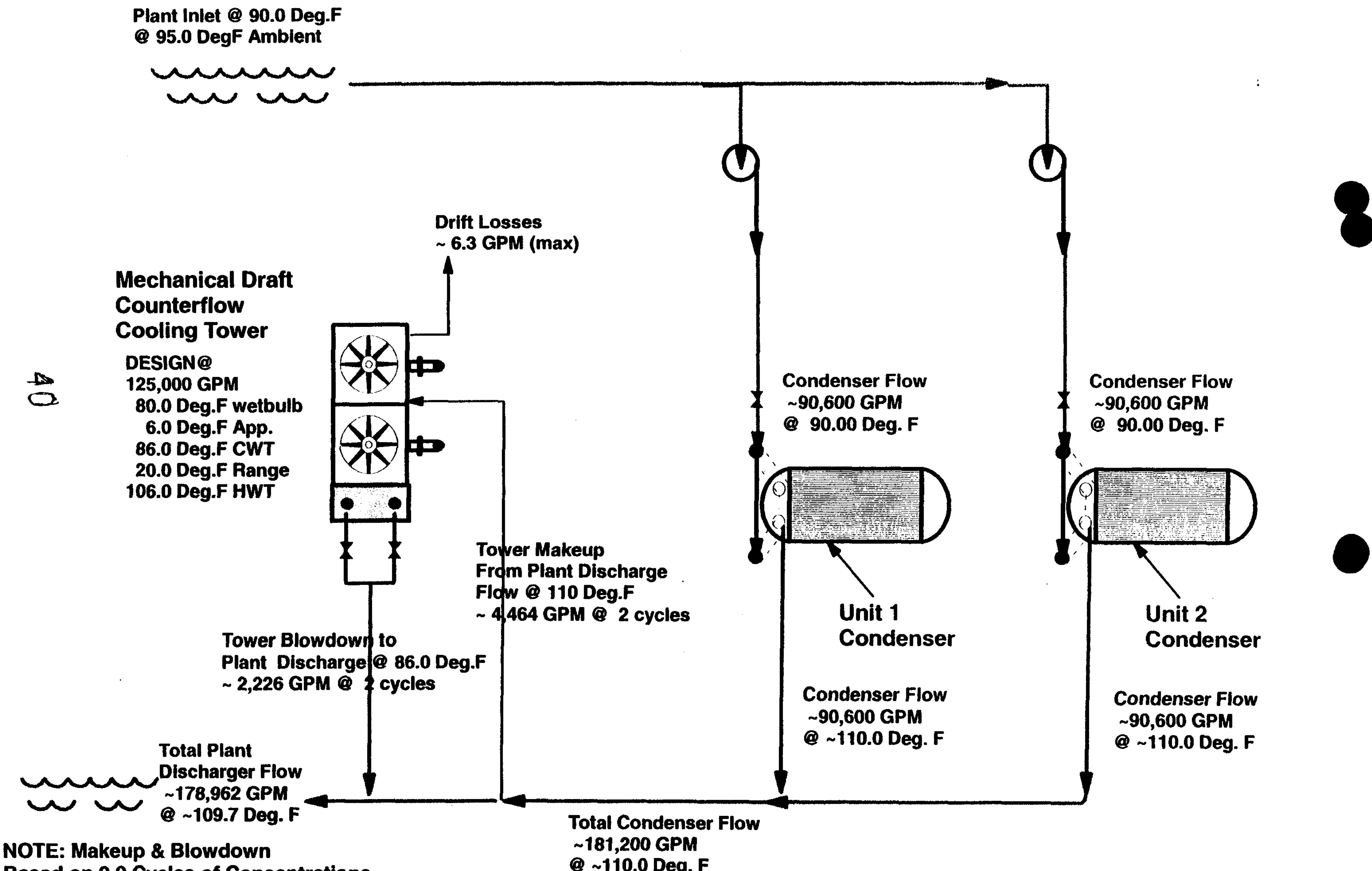
cc: Tom Turk, Gulf Power Company
Al Linero, Florida Department of Environmental Protection
Danny Herrin, Southern Company Services
Jim Vick, Gulf Power Company
Tom Davis, Environmental Consulting & Technology, Inc.
Angela Morrison, Hopping Green Sams & Smith

19. Page 76 of the Need Study states in part, "[c]ondenser cooling for Smith Unit 3 will be accomplished by a closed-cycle cooling tower system, which will minimize cooling water withdrawals and discharges." Provide all documents which Gulf Power used to support this statement.

RESPONSE:

See (1) Lansing Smith combined Cycle Project - Closed Loop Cooling System/Service Water Cycle Schematic (2 pages), (2) Blowdown requirements, and (3) Impact on Plant Discharge Temperature - Estimated for the response to this request.

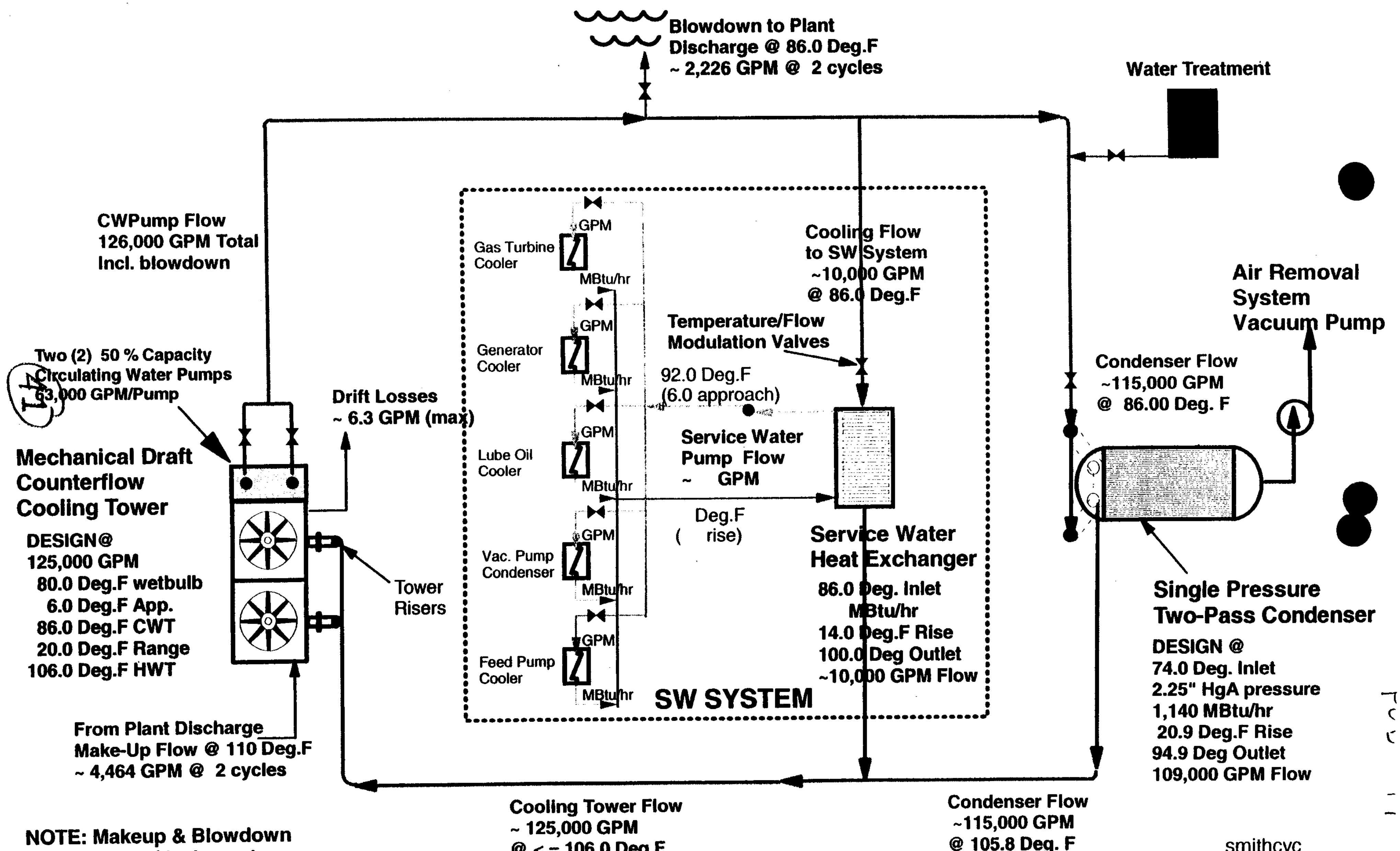
LANSING SMITH COMBINED CYCLE PROJECT
Closed Loop Cooling System / Service Water Cycle Schematic
Preliminary



NOTE: Makeup & Blowdown
Based on 2.0 Cycles of Concentrations

smithcyc

LANSING SMITH COMBINED CYCLE PROJECT
Closed Loop Cooling System / Service Water Cycle Schematic
Preliminary



NOTE: Makeup & Blowdown
are maximum/design values

smithcyc

Preliminary

Lansing Smith Combined Cycle

COOLING TOWER MAKEUP/BLOWDOWN REQUIREMENTS

TOWER FLOW	125,000	GPM		CONDENSER	S.W. FLOW
DRIFT RATE	0.005	% APPROX.		115,000	10,000
EVAPORATION RATE	1.79	% EST.	(MECH. DRAFT TOWER)		

Tower Flow GPM	CYCLES NO.	Evap.Rate %/100	Drift %/100	EVAP GPM	DRIFT GPM	Blowdown GPM	Makeup GPM	Blowdown Gal. Per Day	Makeup Gal. Per Day
125,000	0	0.0179	0.00005	2,232	6.3	5,383	7,620	7,751,520	10,972,800
125,000	1	0.0179	0.00005	2,232	6.3	3,342	5,580	4,812,120	8,035,200
125,000	2	0.0179	0.00005	2,232	6.3	2,226	4,464	3,205,080	6,428,160
125,000	3	0.0179	0.00005	2,232	6.3	1,110	3,348	1,598,040	4,821,120
125,000	4	0.0179	0.00005	2,232	6.3	738	2,976	1,062,360	4,285,440
125,000	5	0.0179	0.00005	2,232	6.3	552	2,790	794,520	4,017,600
125,000	6	0.0179	0.00005	2,232	6.3	440	2,678	633,816	3,856,896
125,000	7	0.0179	0.00005	2,232	6.3	366	2,604	526,680	3,749,760
125,000	8	0.0179	0.00005	2,232	6.3	313	2,551	450,154	3,673,234
125,000	9	0.0179	0.00005	2,232	6.3	273	2,511	392,760	3,615,840
125,000	10	0.0179	0.00005	2,232	6.3	242	2,480	348,120	3,571,200
125,000	11	0.0179	0.00005	2,232	6.3	217	2,455	312,408	3,535,488

MAKEUP = MAKEUP TO TOWER FLOW = DRIFT + EVAPORATION + BLOWDOWN
CYCLES = CYCLES OF CONCENTRATION
EVAP = CIRCULATING WATER FLOW LOSS DUE TO EVAPORATION - GPM = 0.0009 X GPM X TWR RANGE
DRIFT = CIRCULATING WATER FLOW LOSS DUE TO DRIFT - GPM
BLOWDOWN = LOSS OF CIRCULATING WATER FLOW DUE TO CONCENTRATION OF CYCLES
BLOWDOWN = (EVAP /(CYCLES - 1))-DRIFT

CONDENSER FLOW	115,000	GPM		
SERVICE WATER FLOW	10,000	GPM		
DESIGN TOWER FLOW	125,000	GPM		
DESIGN CONDENSER DUTY	1,180	MBtu/Hr		
COND. RANGE = Q / (.0005 X COND.FLOW)	20.52	DEG.F		
DESIGN SERV. WATER DUTY	60	MBtu/Hr	Condenser GPM	115,000
TWRQ = TOWER Q (DUTY) =	1240	MBtu/Hr	Service Wtr GPM	10,000
TOWER RANGE = COND. RANGE	19.84	DEG.F	Blowdown GPM	738
DESIGN TOWER EVAP = 0.0009 X TWRFLOW X DESIGN TWRANGE	2232	GPM	CW Pump GPM	125,738
DESIGN TOWER EVAP = % OF DESIGN TOWER DESIGN TOWER FLOW	1.79	%	CW Pump Design	126,000
ACT. TWRANGE = DESIGN TWRQ / (.0005 X DESIGN TOWER FLOW)	19.84	DEG.F	GPM/ Pump	63,000
ACTUAL TOWER EVAP = 0.0009 X TWRFLOW X ACTUAL TWRANGE	2232	GPM		
ACTUAL TOWER EVAP = % OF DESIGN TOWER DESIGN TOWER FLOW	1.79	%		twrevap

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Preliminary

Lansing Smith Combined Cycle
Closed Loop Cycle - Impact on Plant Discharge Temperature - Estimated

Unit 1 Condenser Flow	90,600	GPM	
Unit 1 Condenser Heat Load - MMBtu/Hr	880	MBtu/Hr	
Unit 1 Condenser Range - Deg.F	19.43	DEG.F	
Unit 2 Condenser Flow	90,600	GPM	
Unit 2 Condenser Heat Load - MMBtu/Hr	880	MBtu/Hr	
Unit 2 Condenser Range - Deg.F	19.43	DEG.F	
Total Units 1 & 2 Condenser Discharge Flow	181,200	GPM	
Condenser Inlet Temperature - Deg.F	90.00	DEG.F	@ 95 Deg.F Ambient
Condenser Outlet Temperature - Deg.F	109.43	DEG.F	
Combined Cycle Tower Makeup Flow - GPM	4,464	GPM	@ 2.0 Cycles
Total Units 1&2 Condenser Discharge Flow after makeup withdrawal	176,736	GPM	
Units 1 & 2 Condenser Discharge Temp.	109.43	DEG.F	
Combined Cycle Tower Blowdown Flow - GPM	2,226	GPM	@ 2.0 Cycles
Combined Cycle Tower Blowdown Temp - Deg.F	86.00	DEG.F	@ 95 Deg.F Ambient
Total Plant Discharge Flow (Condenser + Tower Makeup)	178,962	GPM	
Plant Discharge Flow Temperature - Deg. F (mixed)	109.13	DEG.F	
Differential in Plant Discharge Flow Temperature - Deg. F	0.29	DEG.F	Lower
Differential in Plant Discharge Flow - GPM	2,238	GPM	Lower

twrevap

FCU-1-1

Staff's First Request for
Production of Documents
Docket No. 990325-EI
GULF POWER COMPANY
April 19, 1999
Item No. 21

21. Please provide all support documentation, data, and analysis which Gulf used to determine the cost of expected unserved energy.

RESPONSE:

The response to this request is contained in the following documents:

a. An Economic Study of the Optimum Reserve Margin and associated Reliability Indices for the Southern Electric System - March 1991, attached;
b. An Economic Study of the Optimum Reserve Margin and associated Reliability Indices for the Southern Electric System - March 199, attached;
c. An Economic Study of the Optimum System Planning Reserve Margin for the Southern Electric System - July1997, attached;
d. Survey of Customer Outages (RCG Hagler/Bailly), March 1991, filed under a Letter of Intent for Confidential Treatment.

An Economic Study of the Optimum System Planning Reserve Margin for the Southern Electric System

July 1997

SOUTHERN COMPANY

Energy to Serve Your World™

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EXECUTIVE SUMMARY

The objective of this study was to review and redefine, if necessary, the optimum system planning reserve margin for the Southern electric system ("system"). This planning reserve margin is, in general, defined as the appropriate level of generation resource reserves required to provide for an acceptable level of system generation reliability. This study which results in a recommended optimum or appropriate level of generation reserves for planning purposes is based on economics. Basically, the attempt is to balance the cost of building or procuring new generation resources for reserve purposes with the cost of outages associated with firm load curtailments caused by a lack of reserves. This type of study has been conducted on more than one occasion in the past. This report documents a review of system generation reliability based on new assumptions and improved techniques. It should be noted that an economic analysis is only one piece of information used to determine an optimum generation reliability level. No decision of this importance should be made solely with a series of mathematical models. Industry experience, system operations input, perceptions of acceptable risks, and an understanding of the strengths, weaknesses, and biases of the mathematical models must all be considered in determining the amount of capacity which should be added to the system in the late 1990s and the early 2000s.

Due to construction costs, it may be prohibitively expensive in terms of customers' electric bills to build a power system that would never experience a firm load curtailment due to a deficiency in generating unit capacity. Conversely, it may also be prohibitively expensive in terms of the cost of customers experiencing periods of expected unserved energy to build a power system which often experiences firm load curtailments caused by deficiency in generating unit capacity. As previously stated, for this study, the appropriate level of reserves is defined as the level which balances the cost of total electric service with the cost of outages resulting from firm load curtailments due to generation deficiency.

"Reserves" or reserve margin is commonly understood and is a method utility planners use to discuss system generation reliability. The analyses performed in this study deal with the rigorous calculation of the effect and number of firm load curtailments as embodied in expected unserved energy (EUE) and loss of load hours (LOLH) statistics. More specifically, it deals with the extent to which one additional block of capacity can reduce EUE or LOLH and compares the cost of that block of capacity with the cost of outages due to generation deficiencies. This cost of outages can also be referred to as (1) value of service reliability; (2) societal cost of outages;

or, (3) the cost of EUE. From this point on, reference to such a cost will be made using the term "cost of EUE."

Using projections of future load growth including probability distributions of load forecast uncertainty; hydro, weather, and generating unit outage variations; estimates of the cost of EUE; and, a variety of other assumptions, a level of EUE was identified at which the change in the cost of EUE was equal to the change in the cost of increasing generating capacity reserves. This information, when combined with other less-quantifiable considerations, led to the current projection of approximately 15% to 20% reserve margin guideline for the mid-to-late 1990s.

<u>This new study resulted in a recommendation to transition from the existing minimum 15% system planning reserve margin to a minimum 13.5% planning reserve margin by 1999.</u> There were two significant changes that produced this result. First, modeling techniques that decreased the EUE and LOLH outputs (compared to previous studies) from the Monte Carlo Frequency and Duration (MCFRED) model were implemented. Secondly, the 1989/1990 cost of EUE estimate was reduced from $8.72/kWh to $4.34/kWh, both in 1996 dollars. The changes to the MCFRED model included improvements to the hydro logic to more accurately simulate actual hydro use. The model was enhanced to allow hydro to be placed in storage for up to three days and reserved (by making economy purchases in non-peak or shoulder peak hours) for peak hour use during a hot summer weekday. This change resulted in lower EUE/LOLH estimates from the simulation model. A value of service reliability (cost of EUE) estimate from a 1989/90 survey of system customers - residential, commercial, and industrial - was based on an almost equal energy distribution between these three customer segments during peak periods. After reviewing the automatic load shedding procedures in place across the system for rotating outages during a time when demand exceeds available generation capacity, the distributions used to develop a single cost of EUE estimate representative of all customer segments were found to be heavily weighted toward the residential segment. Given that the aforementioned survey results showed the cost of EUE associated with the residential customer responses was much lower than for either the commercial or industrial segments, the cost of EUE estimate was lowered significantly. We believe this distribution of automatic load shed is better suited for determining such a cost as opposed to looking at the energy usage levels.

This study was not designed to estimate the appropriate reserve margin for the next 20 or more years. It recognizes that the appropriate reserve margin associated with the optimum minimization of LOLH and EUE can and likely will change over time as the mixture of capacity and load shape characteristics change. This study was designed to estimate the appropriate reserve margin for the late 1990s and early 2000s given this is the period for which capacity commitment or similar decisions must be made. The reliability indices estimated here should be considered valid as we move into the 21st century.

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List of Exhibits Included in the Report

I. ASSUMPTIONS

The following sections of this report (A - S) provide detailed discussions related to the input assumptions associated with a review of Southern electric system ("system") generation reliability. These discussions include:

- an overview of the simulation model used;
- the representation of the performance of generating resources including hydro, steam and peaking units as well as load management and power purchase performance;
- the development of load representation adjusted for weather variations;
- the applicable study year; and,
- appropriate costs to be utilized in the economic analyses of system generation reliability.

A. Reliability Simulation Model

Most commercially available production cost and reliability models use convolution techniques to simulate system operations. These techniques typically combine curves of unit outage rates and loads but neglect the associated chronology of such variables. For many applications, the use of such models is acceptable. However, these models were almost exclusively designed to estimate production costing and fuel budgeting costs, not system reliability. For example, programs based on convolution methods typically assume all units can start and operate in any given hour to serve outages of other units. But there are many hours when units are not operating due to a perceived lack of need and will require hours to start (that is, there are units on "reserve shutdown"). Thus, for many capacity deficiency situations, reserve shutdown units can not be counted on to help serve the load during times of extreme or sudden need. But, again, traditional convolution programs would incorrectly assume this "reserve shutdown" capacity could be used to serve the load and assist in avoiding service interruptions due to a generation deficiency.

Furthermore, convolution-based programs have a limited ability to combine the more technically troublesome features of unit outage profiles and load management programs. It is extremely difficult to adequately model energy-limited resources or devices such as pumped storage hydro (PSH) and conventional hydro with convolution techniques. These types of units have greater potential to increase system generation reliability than would be estimated in deterministic peak shaving applications and a lesser potential than would be estimated using round-the-clock availability. Finally, convolution techniques can be very difficult to visualize and explain.

The decision was made in 1989 to develop a model that uses a distribution of times to repair (TTR) and times to fail (TTF) for individual generating units. The Monte Carlo Frequency and Duration (MCFRED) model was developed to use the historical and projected data concerning how often and for how long, respectively, existing and future generating units fail for estimating the expected number of firm load curtailments at various reserve levels. MCFRED has been continuously undergoing rigorous testing for several years.

Monte Carlo analysis uses a random number generator to determine generating unit availability. For each iteration, the simulation will randomly generate the state of a unit as operating, partially failed, or completely failed and thereby determines if firm load curtailments and associated expected unserved energy (EUE). Repeating the calculation for a series of "iterations" or "draws" causes the rolling average of EUE to converge to a solution (i.e., an expected or likely value). It also provides probability distribution information on the capacity shortages needed to determine the effect of emergency tie assistance. Monte Carlo analytical techniques are by far the best available for estimating system generation reliability.

B. Steam Unit Full Forced Outage Data

Generating units typically operate for a period of time, fail and are repaired, and then operate again. For example, a unit may run from 500 to 1500 hours before it fails, take from 5 to 500 hours to repair, then run again for 500 to 1500 hours.

Data are available which reflect each system generating unit's historical operating performance. An analysis of the data revealed that the steam units are approximately 25% more reliable in July and August than the rest of the year. The increased reliability stems from the high emphasis placed during the summer months on keeping the units running due to the increased demand. In off-peak months, units might be more quickly placed on forced outage because the need for extraordinary efforts to keep them operating is diminished. These reasons for the higher summertime reliability are only conjecture, but actual higher availability (reliability) has been observed and documented. This study used 1991 through 1995 actual operating history data for each existing generating unit. These years reflect the recent excellent availability of the system generating units. However, it may be that this level of performance will not be maintained in the future as the generating facilities age. When this study is periodically revised in the future with input data appropriately updated, changing trends in unit reliability will continue to be incorporated automatically.

The July and August data were used for estimating forced outages for June through September because it is believed that the July and August data represented the best estimate of unit availability during peak periods when the capacity is needed to avoid firm load curtailments. The June historical data showed higher forced outage rates, possibly because June is often not as capacity constrained and there is a willingness to bring units down in June to insure they are prepared to run during the typically hotter stretch in July and August. Another factor giving more forced outages in June is that all units are inspected before the summer; therefore, many "small" maintenance items may be identified and repaired in early June. MCFRED simulation of the remaining months (October through May) used the data for all months excluding June - September.

Typical data for a unit might have 8-12 entries in the time-to-fail (TTF) input data record ranging from 25 to 1000 hours and 8-12 entries in the time-to-repair (TTR) ranging from 3 to 150 hours. As MCFRED processes chronologically, it will randomly choose TTF duration from the first data record and then randomly choose TTR duration. Individual unit operation is therefore a direct reflection of what has happened over the previous five years. Since units are independent of each other it is possible that many units can be down at once. An example of this type of input data is given in Exhibit I.B1.

Examples of Time to Failure Data and Time to Repair for Bowen Unit 1							
Type of Data	**Unit Name**	**Hours**					
Full Outage Time-to-Failure Data	BOWEN 1	2087	1860	1195	11	419	68
Full Outage Time-to-Failure Data	BOWEN 1	1360	976	3	2474	1357	184
Full Outage Time-to-Repair Data	BOWEN 1	58	19	74	2	26	16
Full Outage Time-to-Repair Data	BOWEN 1	2	2	5	14	9	4

Exhibit I.B1

Although most steam units have their own specific history that is used in MCFRED, some similar units at one site were grouped for efficient outage data purposes. A forced outage event that occurs at some generating plant's Unit 1, for example, could happen at Unit 2. A larger sample size of forced outage events from which MCFRED can randomly sample is developed for some units using this logic. Forced outage rates, ratios of failed hours to operating hours, or ratios of failed hours to total hours, are outputs of MCFRED rather than inputs. Exhibit I.B2 below displays mean-time-between-failures data for peak and off-peak time periods by unit name. This table is provided for summary purposes; it is not used for data development or modeling purposes.

Exhibit I.B2

FACTORS TO MODIFY THE SERVICE TIME BETWEEN FAILURE DISTRIBUTION							
Unit Name	Summer Mean Time Between Failures	Winter Mean Time Between Failures	Off-Peak Mean Time Between Failures	Annual Mean Time Between Failures	Summer Peak Factor	Winter Peak Factor	Off-Peak Factor
ARKWRIGHT	549.21	741.00	650.00	597.13	0.91974	1.24093	1.08854
ATKINSON	232.95	36.00	133.21	185.64	1.25484	0.19392	0.71757
BARRY 1-2	4632.00	9046.00	1648.35	2193.87	2.11134	4.12331	0.75134
BARRY 3	3601.00	5867.00	1759.43	2218.18	1.62341	2.64497	0.79319
BARRY 4	3504.50	1568.25	1755.36	1893.25	1.85105	0.82834	0.92717
BARRY 5	566.67	491.73	421.28	473.23	1.19744	1.03908	0.89022
BOWEN 1-2	855.00	694.21	980.26	935.38	0.91406	0.74217	1.04797
BOWEN 3-4	839.65	810.76	798.67	836.30	1.00401	0.96947	0.95501
BRANCH 1	1034.57	1589.67	2479.40	1840.50	0.56211	0.86371	1.34713
BRANCH 2	1798.75	790.80	928.04	1041.12	1.72770	0.75957	0.89139
BRANCH 3	640.18	497.36	805.69	703.63	0.90983	0.70686	1.14505
BRANCH 4	1190.83	361.93	499.84	532.41	2.23670	0.87981	0.93883
CHICKASAW 3	99.69	381.00	597.00	252.40	0.39498	1.50951	2.36529
CRIST 1-3	447.67	76.75	261.93	342.75	1.30610	0.22392	0.76421
CRIST 4-5	1389.10	544.83	1379.23	1141.95	1.21643	0.47711	1.20779
CRIST 6	1145.67	1052.20	868.29	942.31	1.21580	1.11661	0.92145
CRIST 7	830.25	202.74	515.00	438.09	1.89518	0.46279	1.17557
DANIEL	2250.17	866.13	1366.70	1399.55	1.60778	0.61886	0.97658
EATON	2554.33	3251.00	4840.00	3251.00	0.78581	1.00000	1.42725
FARLEY	2948.20	2031.14	2094.91	2345.50	1.25696	0.86597	0.89316
GADSDEN	1714.71	557.50	2462.67	1787.05	0.95952	0.31197	1.37806
GASTON 1-4	1424.65	970.60	1044.70	1128.07	1.26291	0.86041	0.92609
GASTON 5	357.89	227.77	329.48	312.78	1.14423	0.72822	1.05340
GORGAS 10	766.78	751.75	397.13	475.70	1.61190	1.58031	0.81382
GORGAS 6-7	1601.11	1423.33	2523.29	2058.25	0.77790	0.69153	1.22594
GORGAS 8-9	1811.63	1158.92	1340.26	1391.98	1.30147	0.83257	0.96284
GREENE CO.	950.60	882.67	1224.66	1094.73	0.86834	0.80629	1.11868
HAMMOND 1-3	2047.78	2853.33	978.70	1279.70	1.60020	2.22968	0.76478
HAMMOND 4	295.15	654.57	438.32	406.75	0.72563	1.60951	1.07762
HATCH	4904.33	4766.33	1487.83	2046.03	2.39700	2.32955	0.72718
KRAFT 1-2	1007.22	98.60	781.74	763.34	1.31949	0.12917	1.02410
KRAFT 3	688.00	574.00	681.53	680.19	1.01148	0.84388	1.00197
KRAFT 4	214.75	51.50	208.91	206.79	1.03848	0.24904	1.00057
MCDONOUGH	14752.00	2004.33	1808.89	2277.62	6.47694	0.88001	0.79420
MCINTOSH 1	1280.00	487.50	1088.80	1074.71	1.19102	0.45361	1.01311
MCMANUS 1	444.11	482.92	567.25	482.92	0.91963	1.00000	1.17462
MCMANUS 2	444.11	482.92	567.25	482.92	0.91963	1.00000	1.17462
MILLER	3645.75	3259.71	2061.53	2413.10	1.51082	1.35084	0.85431
MITCHELL 1-2	637.73	187.00	396.57	531.88	1.19902	0.35158	0.74581
MITCHELL 3	1958.67	1270.00	1044.18	1331.43	1.47110	0.95386	0.78426
RIVERSIDE	203.32	203.32	203.32	203.32	1.00000	1.00000	1.00000
SCHERER	1757.73	1434.50	2179.05	1944.86	0.90378	0.73758	1.12042
SCHOLZ	9476.00	4928.00	3716.25	4928.00	1.92289	1.00000	0.75411
SMITH 1	788.56	6349.00	1627.47	1577.79	0.49978	4.02398	1.03148
SMITH 2	557.75	3214.50	1004.35	979.22	0.56959	3.28273	1.02567
SWEATT	8651.00	8651.00	8651.00	8651.00	1.00000	1.00000	1.00000
VOGTLE	2893.80	7350.00	3311.60	3584.18	0.80738	2.05068	0.92395
WANSLEY	7383.00	2029.00	1453.33	1872.85	3.94212	1.08338	0.77600
WATSON 1-3	1184.27	1727.20	3058.25	1727.20	0.68568	1.00000	1.77064
WATSON 4	850.13	2136.00	732.44	868.18	0.97920	2.46031	0.84365
WATSON 5	491.64	363.14	458.51	459.32	1.07037	0.79061	0.99824
YATES 1-3	746.23	469.79	548.88	603.89	1.23570	0.77794	0.90890
YATES 4-5	635.42	290.57	607.70	599.65	1.05965	0.48457	1.01342
YATES 6-7	1020.54	398.92	959.49	856.67	1.19129	0.46567	1.12002

C. Steam Unit Partial Forced Outage Data

Generating units periodically experience equipment failures which require the units to operate at reduced output. These partial outages are generally much less significant than full forced outages but must still be considered when determining system generation reliability.

In contrast to the results of the full forced outage, units were found to have slightly lower reliability in the summer months in terms of measuring partial outages only. Partial outages occurred more frequently and were repaired more quickly in the summer. One possible explanation for the difference may be that partial deratings are not as often reported in the non-summer months because the units are not called on for economic dispatch as often during that period. On that assumption, the higher level of partial outages is representative of periods when unserved energy will occur. The decision was made to use data based on June through September daytime hours only because this is representative of the time period when partial outages will alter EUE.

For each system generating unit, three data inputs were developed: (1) mean-time-to-failure (MTTF); (2) mean-time-to-repair (MTTR); and, (3) percent duration. MCFRED randomly simulates partial outages based on unit service hours, MTTF, and MTTR. Exhibit I.C1 is an example of the data used. As shown in the exhibit, every 1376 hours of operation for a typical Arkwright unit would be derated by 23.3% for 2.5 hours during the summer peak period. There was little perceived need for a distribution of partial outages due to their anticipated relatively small effect within the analyses.

Exhibit I.C1

1991-1995 GADS Data on Unit Deratings for Use in MCFRED							
Unit Name	Summer Mean Time To Repair	Summer Percent Reduction	Winter Mean Time To Repair	Winter Percent Reduction	Off-Peak Mean Time To Repair	Off-Peak Percent Reduction	Mean Service Time Between Deratings
ARKWRIGHT	2.465	23.3266	9.195	22.8385	2.29	39.3357	1376.0
ATKINSON	51.704	11.7702	51.704	11.7702	21.94	31.7460	7240.0
BARRY 1-2	0.663	53.8793	14.340	15.6904	13.24	39.0633	2056.8
BARRY 3	67.643	4.0901	3.190	10.9718	2.92	42.7838	3428.1
BARRY 4	8.267	10.8871	1.514	36.7925	27.80	34.0100	860.6
BARRY 5	9.209	8.9043	4.050	44.4444	31.08	20.0222	1046.8
BOWEN 1-2	27.650	18.0585	32.731	11.1873	36.39	11.1440	561.2
BOWEN 3-4	9.919	15.7525	10.046	25.8818	19.31	26.8185	511.1
BRANCH 1	12.592	13.3016	19.097	35.9574	14.34	18.2731	1673.2
BRANCH 2	35.105	45.2381	17.992	30.0642	9.03	18.8564	424.2
BRANCH 3	4.455	25.1403	21.154	36.1634	17.48	20.4768	677.1
BRANCH 4	8.410	35.3321	15.787	16.9760	22.37	28.2420	608.5
CHICKASAW 3	51.704	11.7702	51.704	11.7702	21.94	31.7460	5048.0
CRIST 1-3	51.704	11.7702	51.704	11.7702	21.94	31.7460	548.4
CRIST 4-5	3.503	22.4080	3.614	20.8057	4.30	15.4747	76.3
CRIST 6	5.450	29.3230	2.390	24.7699	10.74	25.2283	79.3
CRIST 7	6.495	16.5852	4.323	27.5818	6.74	24.8533	44.9
DANIEL	5.522	16.5636	14.739	15.2651	12.06	18.0391	126.9
EATON	51.704	11.7702	51.704	11.7702	21.94	31.7460	13004.0
FARLEY	42.338	31.7285	19.822	24.4173	37.61	36.3374	2421.2
GADSDEN	2.465	23.3266	9.195	22.8385	2.29	39.3357	37528.0
GASTON 1-4	8.598	14.1512	13.137	22.5598	12.21	26.7754	382.8
GASTON 5	3.613	25.8788	16.238	27.4973	8.71	23.7901	212.0
GORGAS 10	3.047	8.2034	9.570	38.4013	27.70	10.4847	1205.1
GORGAS 6-7	5.324	58.2269	27.250	31.1927	21.22	32.1238	4704.6
GORGAS 8-9	65.467	53.5132	14.699	15.9189	25.73	30.4147	1763.2
GREENE CO	41.440	35.8752	90.287	2.9628	47.83	27.6911	2159.1
HAMMOND 1-3	24.872	14.1554	5.689	19.8393	17.64	21.8331	248.8
HAMMOND 4	22.859	12.9978	30.949	15.9401	36.50	26.2462	133.2
HATCH	69.977	14.8145	60.564	18.7698	50.79	25.2767	368.3
KRAFT 1-2	44.600	7.1749	24.467	4.2234	27.24	4.9550	2714.1
KRAFT 3	8.223	26.6752	109.480	27.1282	54.55	41.8748	855.0
KRAFT 4	401.625	11.5365	664.000	9.3373	1155.01	8.0446	496.3
MCDONOUGH	18.839	23.8113	199.120	20.8058	31.74	23.6485	2346.6
MCINTOSH 1	54.625	14.3937	34.500	9.5652	49.19	34.9499	290.0
MCMANUS 1	51.704	11.7702	51.704	11.7702	21.94	31.7460	6278.0
MCMANUS 2	51.704	11.7702	51.704	11.7702	21.94	31.7460	6278.0
MILLER	2.484	46.4842	5.509	20.1581	8.38	28.2478	750.2
MITCHELL 1-2	7.639	39.1527	7.639	39.1527	36.13	22.9726	671.8
MITCHELL 3	17.137	26.6756	187.060	4.8288	15.97	28.6251	380.4
RIVERSIDE	177.480	24.2140	72.440	16.1510	72.44	16.1510	924.2
SCHERER	5.940	21.6742	6.246	21.0813	6.92	11.4183	641.7
SCHOLZ	5.152	14.2329	5.152	14.2329	32.99	21.4770	724.7
SMITH 1	2.719	21.6092	13.723	19.6474	3.72	32.3812	233.7
SMITH 2	6.261	16.9293	2.315	21.8551	9.21	11.3944	312.3
SWEATT	34.870	19.0898	34.870	19.0898	34.87	19.0698	1235.9
VOGTLE	35.367	31.4554	85.110	9.0706	52.94	25.2603	3285.5
WANSLEY	3.277	13.9494	48.881	1.9042	8.83	8.8588	780.4
WATSON 1-3	23.426	17.1474	74.373	15.8883	20.73	13.5593	164.0
WATSON 4	59.780	4.0010	18.974	22.8887	16.55	13.7328	85.5
WATSON 5	27.057	8.2075	22.536	16.0718	20.96	13.1101	64.3
YATES 1-3	17.947	38.9463	139.315	21.0520	44.81	33.8774	560.0
YATES 4-5	15.830	45.1306	30.067	44.3170	7.14	42.5250	495.4
YATES 6-7	22.772	17.2725	18.208	20.2863	17.72	15.1910	580.3

D. Combustion Turbine Forced Outage Rate and Capacity Rating

The reliability of combustion turbines (CTs) is based on three factors:

1) the probability that the unit is in an available state;
2) the probability that the unit starts if called; and,
3) the probability that the unit continues to run once started.

Appendix A of the report includes a description of the assumptions regarding the availability and expected performance of system peaking capacity resources (i.e., CT units). In summary, the existing system CTs prior to 1993 either had basically the same performance characteristics of the Wilson and McManus CTs (located in the Georgia Power Company service territory) or as a group defined as "other" or non-Wilson/McManus CTs. The CT units installed after 1993 are referred to as the "new " CTs and have, in general, better performance and availability characteristics than the pre-1993 units. Exhibits I.D1 - I.D3 provide patterns, respectively, of hour-by-hour probabilities that a CT will: (1) start, and if it starts; (2) the probability that it will run through the first hour; (3) through the second hour; (4) through the third hour; and, (5) so on through 100 hours of operation. Note, if the CT fails, it is assumed to be unavailable until the next day.

Exhibit I.D1

Wilson/McManus CT Failure Rates and Reliabilities							
Hour	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**
1	0.9836	26	0.8972	51	0.8644	76	0.8417
2	0.9733	27	0.8956	52	0.8633	77	0.8409
3	0.9656	28	0.8939	53	0.8623	78	0.8402
4	0.9592	29	0.8923	54	0.8613	79	0.8394
5	0.9538	30	0.8908	55	0.8603	80	0.8386
6	0.9490	31	0.8893	56	0.8593	81	0.8379
7	0.9446	32	0.8878	57	0.8583	82	0.8371
8	0.9407	33	0.8863	58	0.8573	83	0.8364
9	0.9371	34	0.8849	59	0.8564	84	0.8356
10	0.9337	35	0.8835	60	0.8554	85	0.8349
11	0.9305	36	0.8822	61	0.8545	86	0.8342
12	0.9276	37	0.8808	62	0.8536	87	0.8335
13	0.9248	38	0.8795	63	0.8527	88	0.8328
14	0.9221	39	0.8782	64	0.8518	89	0.8320
15	0.9196	40	0.8770	65	0.8509	90	0.8313
16	0.9171	41	0.8757	66	0.8500	91	0.8307
17	0.9148	42	0.8745	67	0.8491	92	0.8300
18	0.9126	43	0.8733	68	0.8483	93	0.8293
19	0.9104	44	0.8721	69	0.8474	94	0.8286
20	0.9084	45	0.8710	70	0.8466	95	0.8279
21	0.9064	46	0.8698	71	0.8458	96	0.8273
22	0.9044	47	0.8687	72	0.8449	97	0.8266
23	0.9025	48	0.8676	73	0.8441	98	0.8259
24	0.9007	49	0.8665	74	0.8433	99	0.8253
25	0.8990	50	0.8654	75	0.8425	100	0.8246

Exhibit I.D2

Non-Wilson/McManus CT Failure Rates and Reliabilities							
Hour	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**
1	0.9728	26	0.8347	51	0.7844	76	0.7504
2	0.9560	27	0.8321	52	0.7828	77	0.7492
3	0.9433	28	0.8296	53	0.7812	78	0.7481
4	0.9330	29	0.8271	54	0.7797	79	0.7469
5	0.9242	30	0.8247	55	0.7782	80	0.7458
6	0.9164	31	0.8224	56	0.7767	81	0.7447
7	0.9095	32	0.8201	57	0.7752	82	0.7436
8	0.9031	33	0.8179	58	0.7738	83	0.7425
9	0.8973	34	0.8157	59	0.7723	84	0.7414
10	0.8920	35	0.8136	60	0.7709	85	0.7403
11	0.8870	36	0.8115	61	0.7695	86	0.7393
12	0.8822	37	0.8094	62	0.7681	87	0.7382
13	0.8778	38	0.8074	63	0.7668	88	0.7371
14	0.8736	39	0.8054	64	0.7654	89	0.7361
15	0.8696	40	0.8035	65	0.7641	90	0.7351
16	0.8658	41	0.8016	66	0.7628	91	0.7340
17	0.8621	42	0.7998	67	0.7615	92	0.7330
18	0.8586	43	0.7979	68	0.7602	93	0.7320
19	0.8553	44	0.7961	69	0.7589	94	0.7310
20	0.8520	45	0.7944	70	0.7577	95	0.7300
21	0.8489	46	0.7926	71	0.7564	96	0.7291
22	0.8459	47	0.7909	72	0.7552	97	0.7281
23	0.8429	48	0.7893	73	0.7540	98	0.7271
24	0.8401	49	0.7876	74	0.7528	99	0.7262
25	0.8374	50	0.7860	75	0.7516	100	0.7252

Exhibit I.D3

New Peaking CT Failure Rates and Reliabilities							
Hour	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**	**Hour**	**Probability**
1	0.9863	26	0.9136	51	0.8856	76	0.8662
2	0.9777	27	0.9121	52	0.8847	77	0.8655
3	0.9712	28	0.9108	53	0.8838	78	0.8649
4	0.9659	29	0.9094	54	0.8829	79	0.8642
5	0.9613	30	0.9081	55	0.8821	80	0.8635
6	0.9573	31	0.9068	56	0.8812	81	0.8629
7	0.9536	32	0.9055	57	0.8804	82	0.8623
8	0.9503	33	0.9043	58	0.8796	83	0.8616
9	0.9472	34	0.9031	59	0.8788	84	0.8610
10	0.9444	35	0.9019	60	0.8780	85	0.8604
11	0.9417	36	0.9008	61	0.8772	86	0.8597
12	0.9392	37	0.8996	62	0.8764	87	0.8591
13	0.9369	38	0.8985	63	0.8756	88	0.8585
14	0.9346	39	0.8974	64	0.8748	89	0.8579
15	0.9325	40	0.8963	65	0.8741	90	0.8573
16	0.9304	41	0.8953	66	0.8733	91	0.8567
17	0.9285	42	0.8942	67	0.8726	92	0.8561
18	0.9266	43	0.8932	68	0.8718	93	0.8555
19	0.9248	44	0.8922	69	0.8711	94	0.8549
20	0.9230	45	0.8912	70	0.8704	95	0.8544
21	0.9213	46	0.8902	71	0.8697	96	0.8538
22	0.9197	47	0.8893	72	0.8690	97	0.8532
23	0.9181	48	0.8883	73	0.8683	98	0.8527
24	0.9165	49	0.8874	74	0.8676	99	0.8521
25	0.9150	50	0.8865	75	0.8669	100	0.8515

As previously stated, it is assumed that the new CTs will be more reliable than the average of the existing units. Increased reliability results from installation of combustion turbines with improved controls and auxiliary equipment and place them at primary CT sites where maintenance will be superior. As an example, the "new" CTs are expected to have a 3 to 4 percent forced outage rate rather than the 10% in older CTs at coal plants. It is expected that the new machines entering utility service will increase the industry reliability statistics, and consequently, the increased reliability will automatically be incorporated in future updates of the reserve margin study accordingly.

Maximum unit capacity ratings for system combustion turbines (CTs) are determined at the point on the heat rate curve where the ambient air inlet temperature is 95 degree F. Exhibit I.D4 identifies the approximate ratings of existing system CTs.

Exhibit I.D4

System CT Ratings (MW)	
Unit Name	**Rating at 95°F**
ARKWRIGHT 5A	15.1
ARKWRIGHT 5B	13.6
ATKINSON 5A	34.5
ATKINSON 5B	34.5
BOULEVARD 1	15.5
BOULEVARD 2	16.2
BOULEVARD 3	14.7
BOWEN 6A	32.0
GASTON A (100%)	17.0
GREENE COUNTY	333.8
GREENE COUNTY	417.3
MCDONOUGH 3A	34.5
MCDONOUGH 3B	34.5
MCINTOSH	159.2
MCINTOSH	159.2
MCINTOSH	318.5
MCMANUS 3A	50.8
MCMANUS 3B	50.8
MCMANUS 3C	50.8
MCMANUS4B	50.8
MCMANUS4C	50.8
MCMANUS4D	50.8
MCMANUS4E	50.8
MCMANUS4F	50.8
MITCHELL4A	33.1
MITCHELL4B	33.1
MITCHELL4C	33.1
PRATT WHITNEY	16.1
SMITH A	31.6
SWEATT A	35.0
WANSLEY5A	54.0
WATSON A	35.2
WILSON 5A	49.2
WILSON 5B	49.2
WILSON 5C	49.2
WILSON 5D	49.2
WILSON 5E	49.2
WILSON 5F	49.2

E. System-Owned Conventional Hydro Generation

The determination of the reliability impact of conventional hydro generation is one of the major reasons for converting to a chronological, Monte Carlo-based model for system simulation.

The operational flexibility of the conventional hydro is very complex to model. The logic and data in the MCFRED simulations have been designed to balance some conservative assumptions (underestimating hydro's ability to reduce EUE) with some optimistic assumptions (overestimating hydro's ability to reduce EUE) that result in a valid estimation of the impact of the conventional hydro.

A system-owned hydro capacity of 2391 MW (projected for the year 1999) was divided into three components: (1) run-of-river (ROR); (2) scheduled hydro; and, (3) emergency or "unloaded" hydro. The run of river capacity operates in every hour. It varies from a high of 958 MW in March to a low of 30 MW in any summer month (June - September).

Dispatchers refer to scheduled hydro as Block 1 hydro. The sum of ROR hydro and Block 1 hydro was modeled to always equal a maximum available capacity of 1511 MW. The Block 1 hydro is dispatchable to meet system needs.

Emergency or "unloaded" hydro is referred to as Block 2 hydro. This block composes the remaining 880 MW (2391 MW minus 1511 MW) of system hydro capacity. As will be described later, it is reserved for emergencies in the reliability model. During normal system operations when there are fewer concerns about system reliability, reserving the Block 2 hydro generally represents a more efficient use of the water and the overall generating system.

The major constraint in dispatching conventional hydro involves the assumptions concerning how willing dispatchers are to "hold back" the conventional hydro generation. If, for example, the weather forecasts indicate a heat wave will move in later in a summer week and if the capacity situation is tight, the dispatchers will consider restricting operation of the conventional hydro early in the week. MCFRED calculates the conventional hydro energy available in each day, due to natural in-flow. That amount of hydro is available every day if needed for reliability purposes. MCFRED also looks back three days to see if some of the natural in-flow was not used in that period. (Note that the three-day period was designed to represent storage capacity behind the dams and flexibility available in building up or draining ponds as reliability needs dictate.) The daily hydro limit is the sum of today's natural in-flow and any energy not used in the previous three days. Therefore, the maximum conventional hydro energy available on any day under any situation is four days of energy. For a series of capacity constrained days, only the normal in-flow energy will be available near the end of the series each day. This modeling approach resulted in much lower and more accurate EUE projections than the traditional production cost approach of simply adjusting loads for scheduled hydro operation. Simply adjusting the loads is acceptable for production cost programs, but not for reliability analysis.

Block 1 hydro is assumed to be available twice as many hours per week as the Block 2 hydro within the overall weekly energy constraint. In normal weather, for example, Block 1 hydro is available in August for about 30 hours per week and Block 2 hydro is available for about 15 hours per week. Since dispatchers have more flexibility than this fixed ratio recognizes, this assumption could slightly overestimate EUE.

Exhibit I.E1 is a table that depicts average flow information that can be expected over twelve (12) months for the three major components of system-owned hydro generation. Because the system-owned hydro capacity of 2391 MW and the emergency (or Block 2) hydro of 880 MW are fixed amounts, the ROR and scheduled hydro are adjustable within the 1511 MW parameter. The table illustrates how that adjustment may typically occur in an average year when comparing the run of river and Block 1 capacity columns. When ROR capacity has been determined, the ROR energy is a simple calculation. The total monthly energy is the sum of ROR and dispatchable energy. The dispatch energy is the sum of Block 1 and Block 2 hydro energies.

Average Flow Hydro - System-Owned Hydro Generation (SEPA Excluded)

	Maximum		Run-of-River		Avail Hours						
Mon	Cap	Energy GWH	Cap	Energy GWH	Block 1	Block 2	Block 1 Cap	Block 2 Cap	Block 1 Energy GWH	Block 2 Energy GWH	Total Energy GWH
1	2391	791	653	470	216	108	858	880	185	95	751
2	2391	771	757	545	210	105	754	880	158	92	796
3	2391	904	957	689	196	98	554	880	109	86	884
4	2391	786	523	377	264	132	988	880	261	116	754
5	2391	598	312	232	188	94	1199	880	225	83	540
6	2391	399	111	80	133	66	1400	880	186	58	324
7	2391	385	74	55	133	66	1437	880	191	58	304
8	2391	343	30	22	122	61	1481	880	181	54	257
9	2391	322	38	27	111	55	1473	880	164	48	239
10	2391	342	70	28	110	55	1441	880	159	48	235
11	2391	451	175	126	144	72	1336	880	192	63	382
12	2391	591	450	335	140	70	1061	880	149	62	545

Exhibit I.E1

Exhibit I.E2 graphs the hydro energy availability by month to view the differences for peak versus off-peak hydro conditions.

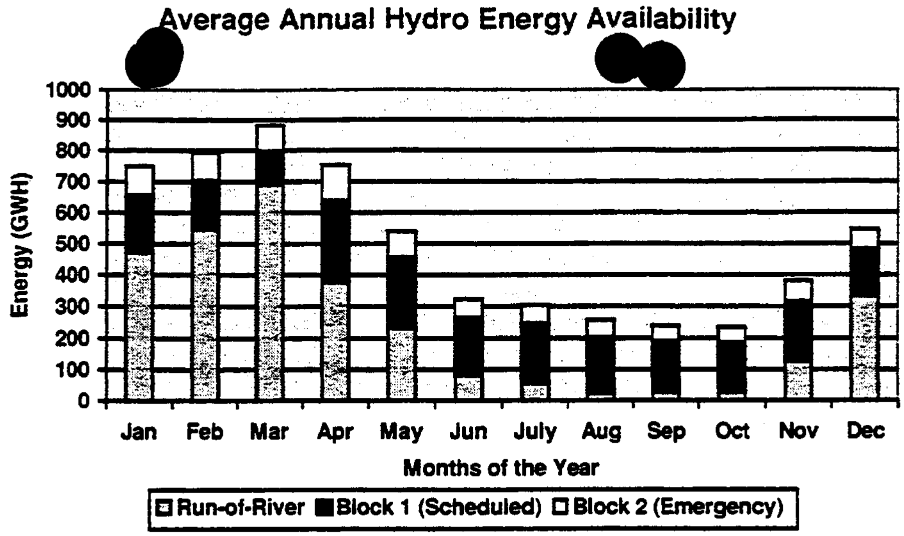

Exhibit I.E2

The development of appropriate hydro probabilistic patterns that encompass over 30 years of hydro energy availability data is included in Section I.N of the report.

F. SEPA Conventional Hydro

The Southeastern Power Administration (SEPA) conventional hydro is less flexible in its operation than the system-owned hydro and its operation is simulated differently. The system has a contractual right to 1045 Megawatt-hours per weekday of SEPA hydro from the large projects, with a maximum operation of 522 MW. This energy was modeled as an adjustment to the system load shape by "clipping" the peak, maintaining both the capacity and energy constraints. SEPA conventional hydro also consists of a number of small projects that were spread over 11 hours for a total of 24 MW.

The option to retain SEPA conventional hydro for use later in the week is sometimes available but it is not a dependable option. This option is ignored and to the extent that it might be available, this modeling method is conservative (overestimating EUE).

G. Pumped Storage Hydro

The pumped storage units are dispatched in reliability order; that is, units with larger ponds are dispatched first. Pumping should and will occur anytime energy is available. In keeping with the goal of calculating EUE, there are no economic tests associated with PSH operation. Alternately, it could be viewed that it is always economic to build up the reservoirs of storage units with any generating asset available if that is what is required to have the units available to operate to avoid unserved energy.

H. Load Management and Steam Peaking Capacity

Approximately 2800 megawatts of load management and steam peaking capacity are included in the analysis. The load management resources include such rates as Interruptible Service (IS) contracts; Real-Time Pricing (RTP); Direct Load Control (DLC), Stand-by Generation (SBG), and Excess Generation (XG) programs; and, a Supplemental Energy (SE) rate. Exhibits I.H1 and I.H2 depict four such Alabama Power Company contracts, two Georgia Power Company contracts, one Mississippi Power Company, three Savannah Electric and Power Company, and one block of steam peaking capacity with varying limitations on their operation. Exhibit I.H1 differentiates between the amount of generation capacity (in MW) in each of these resources as represented in the 1995 Integrated Resource Plan (IRP) and the actual contract amount of capacity (in MW) associated with each. Since the MCFRED model includes the physical constraints (e.g., hours per year, days per week, and hours per day) for these energy-limited resources, the IRP amounts must be adjusted accordingly. This includes making adjustments to the contract amount then accounting for availability and energy loss factors. The equation used within the exhibit for appropriate adjustment is:

$$\textit{IRP Amount} * (\textit{ICE} * \textit{Availability} * \textit{Losses}) / \textit{ICE}$$

The "ICE" factor included in the above equation refers to "incremental capacity equivalent" factors. In general, ICE factors are defined for use in representing the worth of load management resources, such as an interruptible service contract, relative to the value of incremental generating capacity that can be added to the system. Although these resources are a valuable supply-side resource, limitations on their availability have to be considered in studies such as a generation reliability analysis.

Exhibit I.H2 represents the aforementioned contract constraints required by MCFRED in terms of the time periods that these resources are available.

The steam peaking capacity represents additional output available from steam units above their normal ratings that could be used for short periods of time. Of note, the steam peaking capacity

(382 MW) is not included in Exhibit I.H1 since no adjustments are required but it is shown in the second exhibit thus the totals differ by the 382 MW associated with the steam peaking resource.

Exhibit I.H1

IRP and ADJUSTED CAPACITY AMOUNTS FOR LOAD MANAGEMENT RESOURCES - 1999													
1995 IRP AMOUNTS													
	APC						GPC				MPC	SAV		
Year	RTP	200 Hour	600 Hour	Load Cntrl	SBG	XG	240 Hour	RTP	SE	SBG	IL	8760 Hour	SBG	Total
1999	75	539	634	50	94	3	441	410	5	81	8	24	31	2395
ADJUSTMENTS FACTORS														
ICE	0.848	0.833	0.848	1.000	0.848	1.000	0.840	1.000	1.000	0.848	1.000	1.000	1.000	
Avail	1.000	0.930	0.930	1.000	1.000	1.000	0.930	1.000	1.000	1.000	1.000	1.000	1.000	
Loss	1.050	1.050	1.050	1.118	1.118	1.050	1.062	1.000	1.000	1.062	1.000	1.000	1.000	
ADJUSTMENT AMOUNTS (MW)														
	4	-13	-15	6	11	0	-6	0	0	5	0	0	0	-7
MCFRED INPUTS (MW)														
	79	527	619	56	105	3	435	410	5	86	8	24	31	2388

Exhibit I.H2

Load Management and Steam Peaking	Availability				
Description	**Adjusted Capacity MW**	**Hours per Year**	**Hours per Week**	**Hours per Day**	**Days per Week**
Alabama Power Interruptible Service	527	200	40	8	5
Alabama Power Interruptible Service	619	600	40	8	5
Alabama Real Time Pricing (Day Ahead)	79	8760	72	24	3
Alabama Power Stand-by-Generators	105	600	40	8	5
Alabama Power Direct Load Control	56	8760	168	24	7
Alabama Power Excess Generation	3	200	40	8	5
Georgia Power Interruptible Service	435	240	40	8	5
Georgia Power Real Time Pricing (Day Ahead) (1)	335	8760	168	24	7
Georgia Power Real Time Pricing (Hour Ahead) (1)	75	8760	168	24	7
Georgia Power Stand-by-Generators	86	240	40	8	5
Georgia Power Supplemental Energy	5	8760	168	24	7
Mississippi Power Stand-by-Generators	8	240	40	8	5
Savannah Electric Interruptible Service	24	8760	168	24	7
Savannah Electric Stand-by-Generators	31	240	40	8	5
System Steam Peaking (similar to Interruptible Load)	382	263	168	24	7
Total	**2770 (2388 MW without steam peaking)**				

(1) Georgia's RTP contracts are divided into two categories, day ahead and hour ahead, to simulate how the contracts are used in dispatch. The day ahead and hour ahead categories are subdivided into unconstrained and constrained to further simulate contract availability.

These resources occupy specific positions in the dispatch order. The position in dispatch affects their ability to reduce expected unserved energy and alters the frequency with which they are called.

Various load management rates, sometimes referred to as active demand-side options ("active" DSOs), such as interruptible load, cool storage, and direct load control, have gained interest in the past decade. The interruptible load is being handled explicitly in the study, but DSOs that are not dispatchable ("passive" DSOs) are included in the load forecasts and are more difficult to identify discretely.

In general, passive DSOs "flatten" the system load shape, decreasing the gap between the peak load and shoulder loads on hot summer afternoons. Because more reserves are needed to serve the flatter load shapes, an increased emphasis on DSOs can generally be expected to increase the target reserve margin percentage slightly. Viewed another way, a DSO which decreases the load in the afternoon hours but not the early evening will not be as capable in reducing EUE as a CT which is relatively unconstrained in its operation.

Because passive DSO impacts are expected to be relatively small and ramp up over time, it is unlikely the system reserve margin will vary substantially with more "passive DSOs" and as this study is revisited in future years, additional DSOs will be incorporated in the calculations automatically.

I. Emergency Tie Assistance

The key assumption in the incorporation of tie assistance in the simulation is that neighboring utility systems resemble our system.

In addition to determining the probability distribution of system unserved energy by hour, MCFRED also determines the distribution of tie assistance available from the system to other utilities under two different assumptions. Because neighboring systems are assumed to mirror the system, the probability distribution of tie assistance that the system can provide is expected to be a good estimate of the probability distribution tie assistance the system can receive.

MCFRED can estimate the tie assistance available from up to four neighboring systems. The three systems to the "non-South" resemble our system in that they have pumped and conventional hydro capability. The emergency tie assistance (ETA) available from a neighboring system in any hour is defined as any excess (above system load) committed steam generation plus available CTs (derated for starting failures) plus the available Block 1 hydro and pumped storage (derated for pond exhaustion). The ETA available from the South is calculated the same as the North, except conventional hydro is not included. (The pond levels are not checked to reflect the lack of energy limited generation in Florida.)

For the purpose of this study, one utility from the North and one from the South were assumed to be able to supply emergency tie assistance.

There will be many hours when the system cannot supply ETA and does not have unserved energy. This occurs anytime interruptible load or Block 2 hydro has been called. In other words, the system will not interrupt customers or run emergency hydro to provide ETA but also may not buy ETA before taking these two steps.

A subroutine of MCFRED, the Probabilistic Evaluation System for Ties (PEST), uses convolution techniques to combine the unserved energy of neighboring systems with the tie assistance from neighboring systems for each hour of the year. It determines the likelihood that the neighboring systems can supply ETA when the system needs it and incorporates both transmission limits and the probability that both our system and a neighbor may need more ETA than the remaining neighbor can provide.

J. Economy Purchases

If inexpensive energy is available from neighbors, dispatchers will hold back on conventional hydro and pumped storage (which may be needed later) and buy economy energy. By examining historical load shapes, estimates of available economy energy were developed. These estimates were used in MCFRED and then checked for reasonableness with PEST and modified where needed.

Economy purchases were not assumed to be available across the peak hours of any day. The amount of capacity available through economy ties is exemplified in Exhibits I.J1 - I.J4 (each graph containing three months of the year). These assumptions are designed to represent a balance between the need to reflect the existence of economy ties and the need to not rely too heavily on these economy ties to meet demand in critical periods. The true benefit of these non-peak hour purchases is as stated below.

In the final analysis, the economy purchases were more beneficial in reducing EUE than emergency ties due to the synergy between economy ties and the energy-limited hydro. That is, the combination of pumped and conventional hydro available in the summer afternoons and the economy ties available in the morning and late evening is an optimum technique in utilizing available resources to reduce periods and magnitudes of EUE.

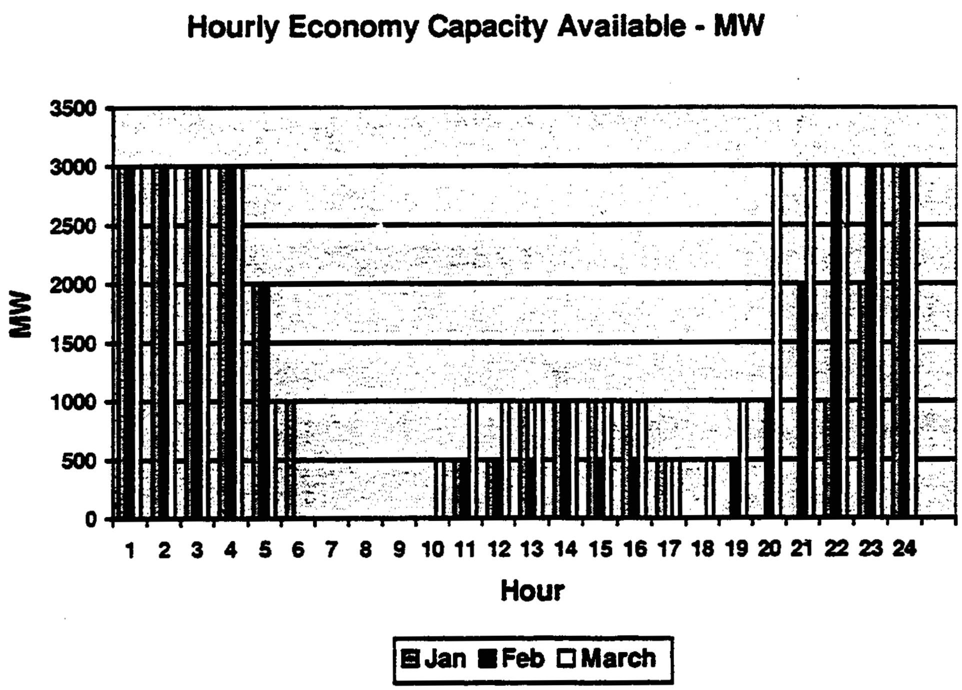

Exhibit LJ1

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SOUTHERN COMPANY

Hourly Economy Capacity Available - MW

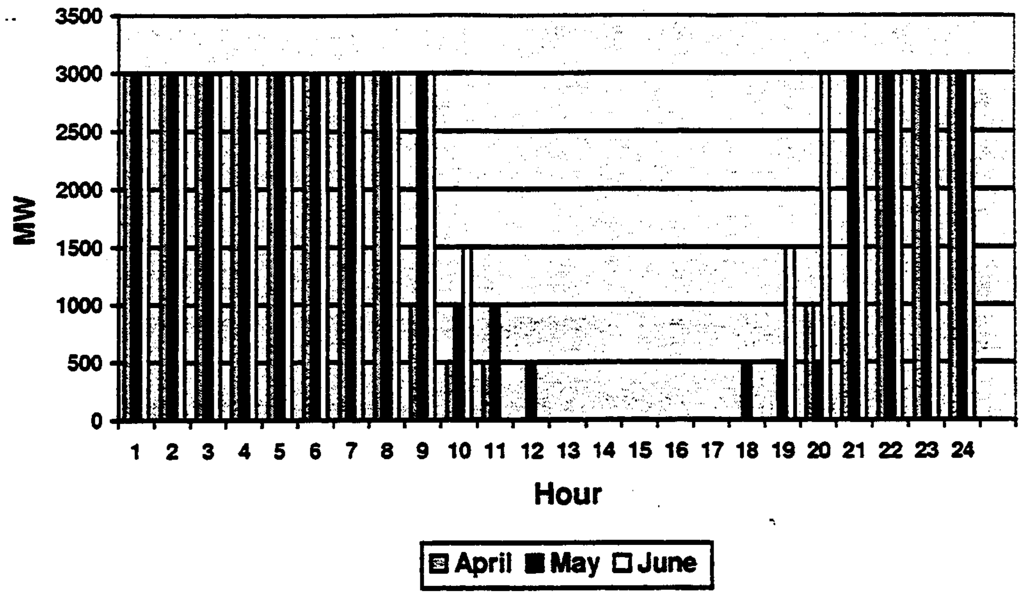


Exhibit LJ2

Hourly Economy Capacity Available - MW

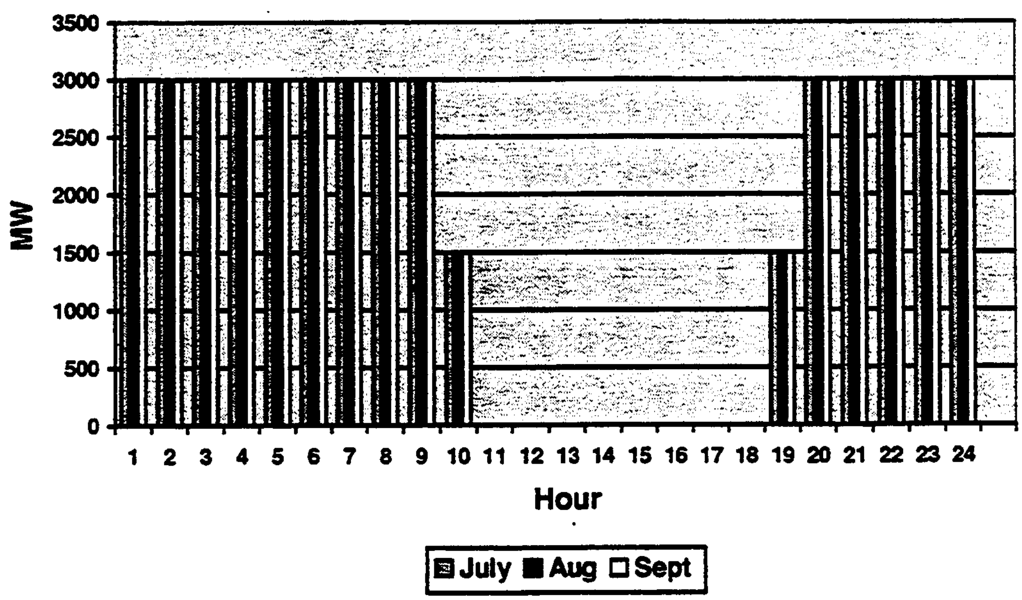


Exhibit LJ3

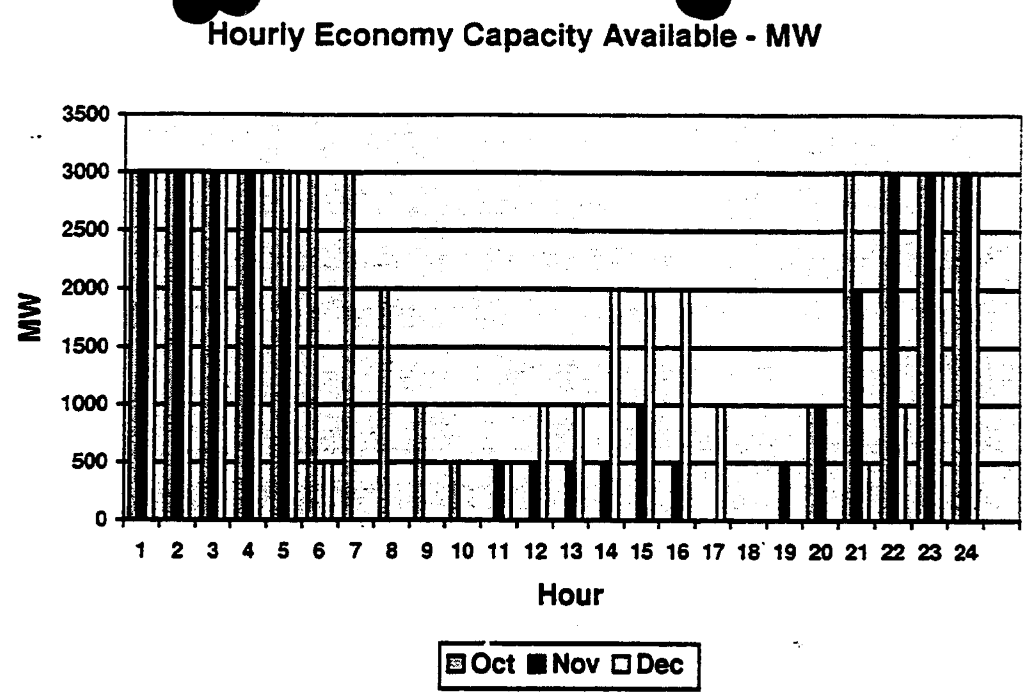


Exhibit I.J4

K. Commitment

Steam resources in MCFRED were committed to match the current operating practices. A target level was calculated by the following formula:

Target Level =

*(MW level of the territorial peak hour of the next 48 hours + expected off system sales) * (1 + Dispatchers' Peak Load Estimate Error) minus (Block 1 Hydro) plus 1200 MW*

The system carries operating reserves of approximately 1800 MW. This is approximately one and one-half (1.5) times the largest system-owned generating unit used to serve territorial load. The 1200 MW of steam included in the above equation are less than this operating reserve. However, the total of the 1200 MW of steam and 880 MW of emergency or Block 2 hydro exceeds this system imposed operating reserve requirement. In actual practice this commitment level will vary across the year with variations in the confidence in the daily load forecasts, hydro availability, and specific situations with the large generating units. This 1200 MW is a reasonable approximation for a variety of situations. During the periods when load is high and EUE is most likely, all steam units will generally be committed. The inclusion of off-system sales in determining the level of commitment increases the service hours of intermediate and higher generating units slightly and therefore increases the frequency of their outages.

The Dispatchers' Peak Load Estimate Error is modeled in MCFRED as a 20-step probability distribution of the error in the dispatchers' projection of the peak expected across the next two days. The error was developed from a comparison of actual loads to the dispatchers' short-term projections and is presented in Exhibit I.K1.

Dispatchers Peak Load Estimate Error																				
% Energy (1)	6.96	3.67	3.30	3.14	3.02	2.38	1.75	1.17	0.80	0.51	0.09	0.06	-0.36	-0.90	-1.10	-1.50	-2.24	-3.29	-4.42	-5.08
Probability(2)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

Notes:

(1) The percent that the forecasted peak differed from the actual peak

(2) The probability that the forecasted peak would differ from the actual peak by the specified percentage

Exhibit I.K1

It is not likely that the input commitment level would have a significant effect on EUE. Within a range of reasonable commitment levels, all steam units would be committed on days when EUE is likely.

L. Weather Years

The unpredictability of weather impacts generation reliability. Historical weather patterns for the last 35 years (1961-1995) and their associated probabilities of occurrence are utilized in the reliability analyses. In general, if weather remains normal over time, concerns for system generation reliability are minimized. However, if the system experiences many days recording abnormal temperatures, system demand would increase significantly. Naturally, extended abnormal temperatures (on the high side in the summer period, and on the low side in the winter period) would increase the risks and potential for system generation related reliability problems.

The historical weather patterns for both summer and winter were analyzed to determine which patterns were more likely to produce EUE and LOLH. For both summer and winter, the weather patterns in 11 of the 35 years would yield essentially zero EUE or LOLH. Abnormal (hotter in the summer or colder in the winter than normal) weather years were modeled to represent the remaining 24 years. A probability of occurrence is assigned to each weather year (for each season analyzed) as well as those weather years when there are no generation reliability concerns.

Refer to Section II.A of the report for a list of the weather years selected for modeling abnormal weather conditions and temperatures for both the summer and winter reliability analyses.

M. Response of System Load to Weather Conditions

A weather normalized load shape or base shape is the starting point for generation reliability modeling. However, to simulate the occurrence of abnormal weather, the base shape is modified to reflect the effect of temperature for weather years chosen to represent abnormal weather patterns (i.e., hot summer months for the summer reliability analysis and cold winter months for the winter reliability analysis). Load files that incorporate the abnormal weather patterns were developed to correspond with the weather years specified in the previous section.

N. Development of Hydro Patterns

Typically, the summer months yield varying weather and hydro conditions in the southeastern United States that influence the peak and energy demands across the system. Being a summer-peaking utility system, the system has significantly higher peaks and energy demand, and subsequently potential for periods of EUE during the hotter summer months due to the higher temperatures. While studying the effects of weather on the generation reliability of the system, a correlative relationship was discovered between temperature and available hydro energy. This study further investigated this interdependence of weather on the availability of hydro energy within the system. By better quantifying this relationship, weather scenarios were expanded to incorporate the effects on hydro. For example, a summer that has extremely hot temperatures and a lack of hydro energy will create the potential for more generation reliability problems than a summer that has extremely hot temperatures and an excess of hydro energy.

As with the weather data, the availability of hydro can vary year-to-year and impacts generation reliability. Three hydro scenarios – wet, normal and dry – were developed from over 30 years of actual hydro data. These three scenarios resulted from graphical development of the amounts of historical hydro energy generated versus the actual load demand. The hydro years with similar energy availability were grouped together. Regression analysis was used to produce a curve for high (wet), likely (normal), and low (dry) generation scenarios for any weather and load pattern. A probability of occurrence is assigned to each hydro generation scenario.

Exhibits I.N1 illustrates how regression analysis was used to create three hydro patterns to represent over 30 years of hydro energies. Obviously, the upper curve represents a high or wet hydro pattern while the lower curve represents a low or dry hydro scenario.

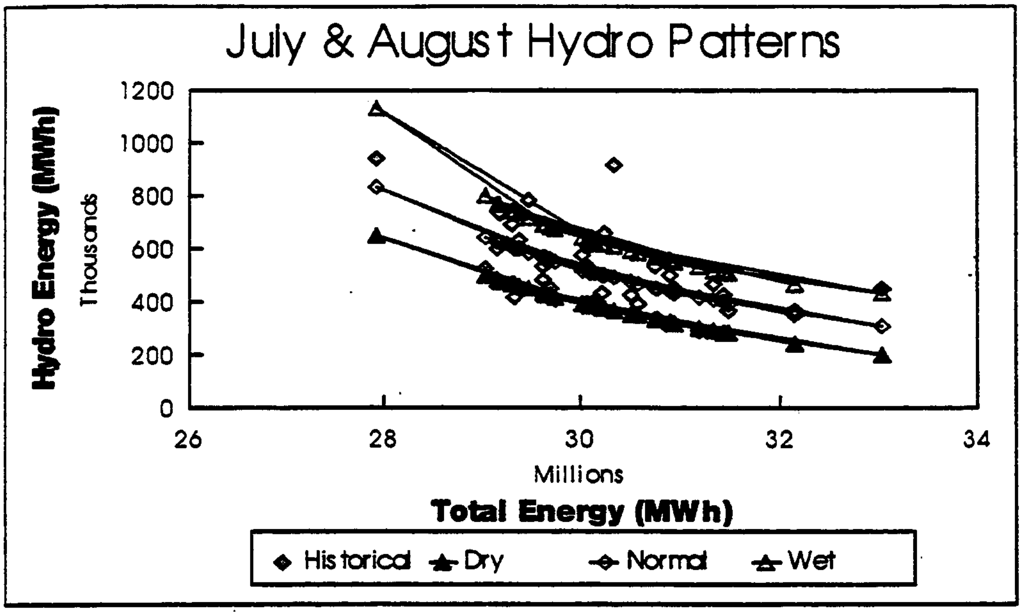


Exhibit I.N1

Exhibits I.N2-I.N4 reflect how these curves were used to create a corresponding hydro year for a selected weather year. These exhibits depict how a 1980-type weather year can be adjusted from a normal hydro availability pattern to one that reflects both a dry and wet pattern.

SOUTHERN COMPANY

Exhibit I.N2 - System-Owned Hydro Generation Hydro Input Data for MCFRED - 1980 Weather Scenario								
Dry or Low Hydro Scenario								
	Maximum		Run-of-River		Block 1	Block 2	Block 1	Block 2
Month	Cap MW	Energy GWH	Cap MW	Energy GWH	Energy GWH	Energy GWH	Monthly Hrs Avail	Monthly Hrs Avail
1	2391	758	653	485	178	95	207	108
2	2391	751	757	508	150	92	199	105
3	2391	900	958	712	101	86	183	98
4	2391	743	523	376	251	116	254	132
5	2391	534	312	232	219	83	183	94
6	2391	169	60	43	98	28	67	32
7	2391	183	60	45	110	28	76	32
8	2391	198	60	45	125	28	86	32
9	2391	95	60	43	38	14	26	16
10	2391	256	70	45	155	49	107	55
11	2391	377	176	126	187	64	140	72
12	2391	331	450	335	143	62	107	70

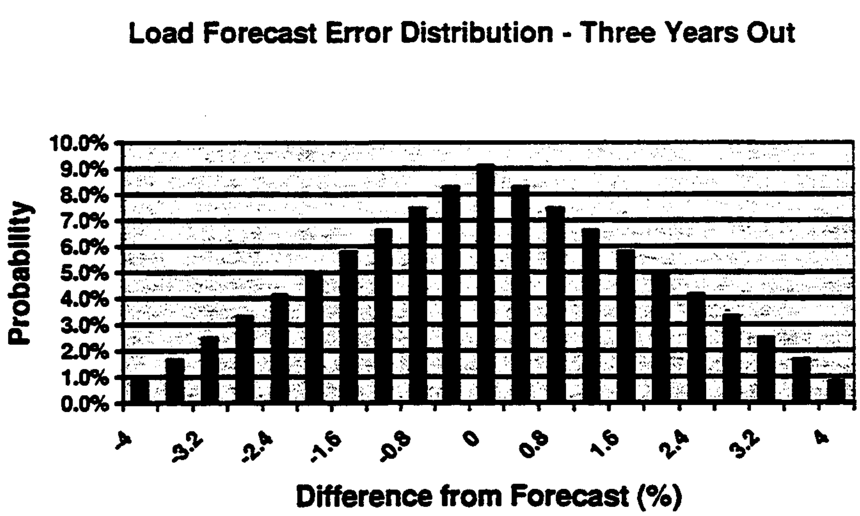
Exhibit I.N3 - System-Owned Generation Hydro Hydro Input Data for MCFRED - 1980 Weather Scenario								
Normal or Likely Hydro Scenario								
	Maximum		Run-of-River		Block 1	Block 2	Block 1	Block 2
Month	Cap MW	Energy GWH	Cap MW	Energy GWH	Energy GWH	Energy GWH	Monthly Hrs Avail	Monthly Hrs Avail
1	2391	758	653	485	178	95	207	108
2	2391	751	757	508	150	92	199	105
3	2391	900	958	712	101	86	183	98
4	2391	743	523	376	251	116	254	132
5	2391	534	312	232	219	83	183	94
6	2391	315	95	68	219	28	155	32
7	2391	215	90	67	120	28	84	32
8	2391	233	90	67	138	28	97	32
9	2391	124	80	58	52	14	37	16
10	2391	256	70	52	155	49	107	55
11	2391	377	176	126	187	64	140	72
12	2391	331	450	335	143	62	107	70

Exhibit I.N4 - System-Owned Generation Hydro Hydro Input Data for MCFRED - 1980 Weather Scenario								
Wet of High Hydro Scenario								
	Maximum		Run-of-River		Block 1	Block 2	Block 1	Block 2
Month	Cap MW	Energy GWH	Cap MW	Energy GWH	Energy GWH	Energy GWH	Monthly Hrs Avail	Monthly Hrs Avail
1	2391	758	653	485	178	95	207	108
2	2391	751	757	508	150	92	199	105
3	2391	900	958	712	101	86	183	98
4	2391	743	523	376	251	116	254	132
5	2391	534	312	232	219	83	183	94
6	2391	413	125	90	295	28	213	32
7	2391	312	120	89	195	28	140	32
8	2391	338	120	89	221	28	159	32
9	2391	275	125	90	157	28	113	32
10	2391	256	70	52	155	49	107	55
11	2391	377	176	126	187	64	140	72
12	2391	331	450	335	143	62	107	70

O. Load Forecast Uncertainty

Even ignoring all variation from normal weather, there remains considerable uncertainty in the load projections for two or three years into the future. Planning to have a minimum 13.5% reserve margin three years into the future will probably result in a reserve margin either less or more than 13.5%. If load grows more quickly than expected, it will be less than 13.5% and the risk of firm load curtailment is greater. Unexpected strength or weakness in the economy can be a source of load forecast error. Structural changes in the way electricity is used is also a source of load forecast error. Load forecast uncertainty three years into the future (the length of time required to get a new combustion turbine on-line) was estimated using historical data. This estimate was found to be a range of approximated by ±4%. A graph showing the resulting load forecast uncertainty distribution is included in Exhibit I.O1. For example, this ±4% uncertainty distribution would equate to a description of the cumulative load growth over three years as a maximum of 11.198%, an expected cumulative load growth of 7.198%, and a minimum of 3.198%. (Note, the expected cumulative load growth is based on the assumption that there exists a one-percent uncertainty in the first year, a 2% uncertainty in the second, and a 4% uncertainty in the third year. The maximum and minimum values are + and - 4 percentage points of the expected value.) Thus the change from the expected compounded load growth is ±4%. A triangular distribution, as graphed in the exhibit, was used to estimate the probability distribution for load forecast error. Using this triangular distribution, the EUE across a probability distribution of load forecast uncertainty is estimated.

Exhibit I.O1



P. Study Year

As mentioned in the executive summary, target reliability studies should not have the goal of determining the one optimum reserve margin across the next 20 or 30 years. It is not necessary to select one long-term goal; the system should not be constrained to keep one constant reliability index. Furthermore, the results of long-term, constant reliability constraints can be clouded by projected changes in load shapes, unit costs, hydro availability, thermal unit availability, and other factors. The decision at hand is the determination of capacity needs for the late 1990s and early 2000s.

For the analyses necessary to determine the incremental change in EUE per additional kilowatt (kW) of capacity installed, **1999 was selected as the test year for the study**. Three years out is approximately the amount of time required to make a decision to install new capacity in terms of design, certification, construction, and operating and maintaining a new generating unit. Although the focus of this study is three years out which is consistent with the planning criteria, it examines the target reserve margins for one and two years out as well (see Results, Section III.A).

Q. Capacity Cost

Simple-cycle combustion turbine (CT) technologies are typically utilized for meeting peaking capacity needs. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral method. The CT cost model is a green-field site of three 120 MW units rated at 95 degrees ambient. In 1996 dollars, the cost of advancing a CT used in the study was about $24.63 per kilowatt-year. It includes the following components:

CT Overnight Cost (1996):	$227.13 $/kW
times the deferral rate	9.39 %
Capital cost of advancing a CT:	21.31 $/kW
plus fixed operations and maintenance, capital modifications, and fuel inventory carrying cost:	3.32
Total Cost	$24.63 $/kW-year

R. Dispatch Order

System dispatchers have flexibility regarding the order in which generating units are called to operate. Steam units are committed as described in Section I.K, generally beginning with the least expensive in terms of operating cost. When steam units are insufficient to or are not the most economical way to meet the electrical demand, the dispatchers can call on a combination of the following options: economy purchases, normally scheduled hydro, pumped storage hydro, combustion turbines, load management, and emergency hydro. The combination and the order of the options called vary with system conditions and projections of the near future -- two or three days.

The following "resources" will be operated or called in this order during most periods of the year, although there are often times when economy and hydro are used before some steam units are dispatched:

(1) all steam units,
(2) economy ties if available,
(3) block 1 hydro,
(4) pumped storage,
(5) combustion turbines,
(6) load management, and
(7) block 2 hydro.

If, however, system conditions are tighter than normal, the pumped storage units might be run before the conventional hydro. If system conditions are tighter still, the CTs can be called before the conventional and pumped hydro. To reflect these options, MCFRED checks the next two days to estimate how tight the system capacity situation is expected to be. If system peak is expected to be between 85% and 95% of available capacity (including all committed, hydro, and quick start units), the dispatch order is revised to move the pumped storage units (with their less-constrained ponds) down, as shown below:

(1) all steam units,
(2) economy ties if available,
(3) pumped storage, } Order
(4) block 1 hydro, } Reversed

(5) combustion turbines,

(6) load management, and

(7) block 2 hydro.

If the system peak is expected to be above 95% of available capacity (including all committed, hydro, and quick start units), the dispatch order is changed to the generation reliability dispatch (or non-economic dispatch) as listed below:

(1) all steam units,

(2) economy ties if available,

(3) combustion turbines, } moved up from (5)

(4) pumped storage,

(5) block 1 hydro,

(6) load management, and

(7) block 2 hydro.

Operating the CT units before the energy-limited hydro reduced EUE in earlier test runs by 80%, resulting in a substantial savings in the need for capacity additions.

Because MCFRED switches dispatch orders dynamically over time, this procedure is called the "dynamic dispatching option." Exhibit I.R1 shows the "stack" under the two extremes of the dispatch.

Order of Dispatch

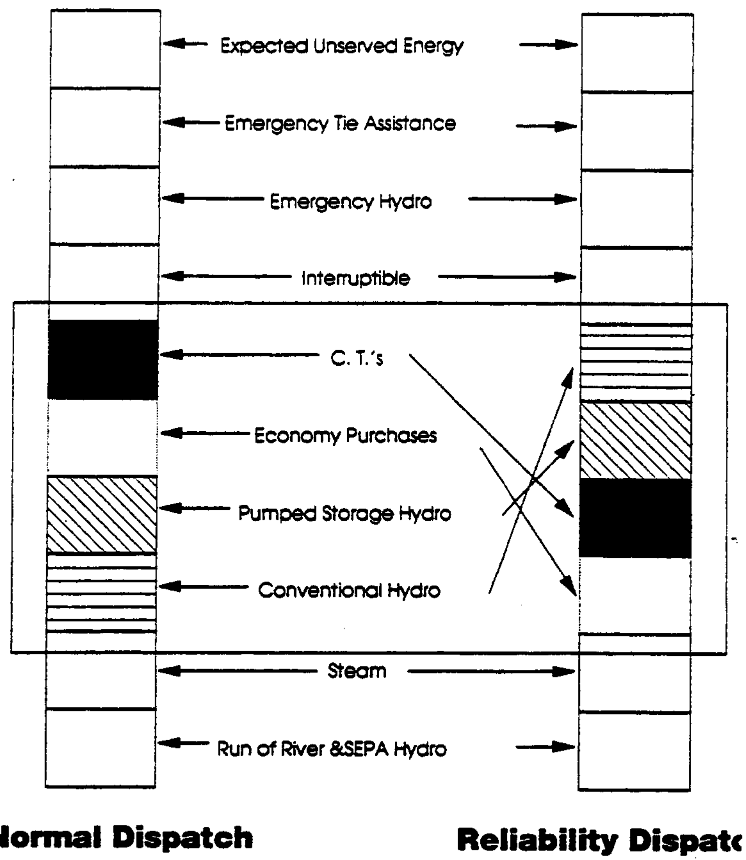


Exhibit I.R1

S. Cost of Expected Unserved Energy

The cost of EUE has been one of the most important and most uncertain of all the assumptions. The payment which one customer is willing to make to avoid an hour of sudden, unexpected firm load curtailment on a hot, summer afternoon is difficult for the customer to estimate. The payment which one customer is willing to take to suffer an hour of sudden, unexpected firm load curtailment on a hot summer afternoon is also difficult to estimate. This information is developed primarily through surveys.

As previously mentioned, this type of study has been conducted in the past. In a report entitled, "An Economic Study of the Optimum Reserve Margin and Associated Reliability Indices for the Southern Electric System, March 1994," the cost of EUE or in the report referred to as the value of service reliability was estimated at $7.31 per kilowatt-hour. This estimate is $8.24 inflated to 1994 dollars. As stated in the aforementioned report, this cost or value is based on equal

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